PRELIMINARY DRAFT REPORT

City of Bainbridge Island
Electric Utility Municipalization
Feasibility Study

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Prepared for

City of Bainbridge Island
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by

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Electric Utility Municipalization Feasibility Study
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Executive Summary

Introduction

The City of Bainbridge Island, Washington (City) retained D. Hittle & Associates, Inc. (DHA) in 2016 to conduct an electric utility municipalization feasibility study. The study is intended to provide a review of the technical and economic issues related to the establishment of an electric utility owned and operated by the City or another public entity. Electric service is presently provided to the residents and businesses on Bainbridge Island by Puget Sound Electric (PSE), a privately-owned electric utility headquartered in Bellevue, Washington. This report summarizes the results and findings of the feasibility study. The law firm of Gordon Thomas Honeywell assisted DHA in the preparation of certain portions of this report.

In general, the concept of establishing a municipal electric utility would involve acquisition of the existing distribution and transmission system in the City, contracting for a supply of electric power and establishing the capability to operate and maintain the electric system. Although most electric utilities retain their own staff to operate their respective systems many operation and maintenance functions can be performed by contractors if desired.

Consumer-Owned Electric Utility Options

Consumer-owned electric utilities, often referred to as public power utilities, are common in the Pacific Northwest and across the United States. They provide all functions of electric service and are directed by board members, commissioners or city council members generally elected from within the service area of the utility. As such, local control is a significant element of public power utilities.

Public power utilities provide electric service at cost and are not-for profit, and with the exception of cooperatives do not pay federal income taxes. They generally have access to loans at tax-exempt interest rates or to loans provided by the federal government at low interest rates. Public power utilities also have preference over private utilities in purchasing power generated at federal hydroelectric resources. In the Pacific Northwest, this is a significant benefit in that most public power utilities, other than those with significant generating resources of their own, purchase all, or nearly all, of their power supply requirement from the Bonneville Power Administration (BPA), a federal power marketing agency. BPA's wholesale price of power is relatively low compared to the cost of power from new generating resources.

The three primary forms of consumer-owned electric utilities are municipal utilities, cooperative utilities and public utility districts (PUDs). Each of these utility types have certain benefits and drawbacks. For the purpose of this analysis, the municipal electric utility option has primarily been evaluated.

Electric Facilities on Bainbridge Island

The electric facilities located within the City include transmission lines, substations, overhead and underground distribution lines, poles, transformers, vaults, service drops, meters, streetlights, right-of-ways and ancillary distribution system facilities. There are three substations on the island that transform power from transmission voltage to the primary distribution voltage. PSE's transmission system on Bainbridge Island consists of approximately 14 miles of 115-kilovolt (kV) overhead transmission lines that connect to PSE's transmission system on the Kitsap Peninsula side of Agate Pass.

PSE indicates that there are 307 miles of distribution lines on Bainbridge Island of which 165 miles are underground. The overhead and underground lines are a mixture of three, two and single phase. In addition, 22 miles of overhead distribution lines use insulated tree wire. Overhead distribution and transmission lines are generally built with typical wood-pole construction and in some areas the distribution lines are underbuilt on transmission poles.

There are several options that the City could take in defining the electric facilities that would be acquired to establish a new electric utility system. It is expected that the substations, distribution lines, transformers, services and meters would be needed for the City to own the distribution system as required by BPA. All of the transmission lines, however, would not necessarily need to be acquired. Instead, PSE could continue to own some or all of the transmission lines on the island and BPA would make arrangements with PSE to deliver power over the lines to the City's substations.

For the purpose of this analysis, we have assumed that PSE would continue to own the transmission lines north of the Port Madison substation. A metering system would be installed at the Port Madison substation and this is where the new utility would take delivery of power from BPA. From this point the new electric utility would own the substations, the radial transmission lines between the substations, all overhead and underground distribution lines, distribution transformers, customer services, and meters.

Estimated Cost of Acquiring Facilities

An appraisal of the value of electric facilities to be acquired by the City for its electric system has not been conducted. Such an appraisal would rely upon a detailed description of the facilities to be acquired and will potentially be needed if the City proceeds towards acquisition of the PSE system on Bainbridge Island.

For the purpose of this analysis, the cost the City would pay for the acquired facilities is estimated to be between the original cost less depreciation (OCLD) value and the reproduction cost new less depreciation (RCNLD) value of the electric facilities. OCLD is defined as the original cost of the property when it was first put into service as a public utility, less accrued depreciation. The OCLD value is an estimate of the net book value of property. The actual purchase price will be either negotiated or established in a court proceeding but should reasonably be expected to be in the range between the OCLD and RCNLD values. We have estimated the RCNLD value of the facilities proposed to be acquired at $48.7 million. The OCLD value is estimated to be $22.7 million.

Estimated Number of Customers and Load Forecast

The number of customers in the City's service territory has been estimated to serve as the basis for estimating energy sales and overall power requirements of the municipal electric system. PSE has indicated that approximately 12,300 electric customers are presently served on Bainbridge Island and that the total number of electric customers served has increased about 0.7% on average per year between 2010 and 2016.

The total annual energy requirement of the City electric system is estimated to be 206,000 MWh, or 23.5 average MW, at present levels. The peak demand is estimated to be 39 MW.

Financing Options and Estimated Cost of Financing

Municipally-owned electric utilities and PUD's generally use tax-exempt revenue bonds and loans to fund the capital costs associated with their systems. Federal tax laws generally prohibit the use of tax-exempt loans for the funding of municipal acquisition of electric systems owned by investor-owned or privately owned utilities. Alternatively, low interest rate financing may be available through the federal Rural Utility Service (RUS).

For the purpose of the base case of this analysis, it is assumed that the acquisition cost of the new utility will be financed with revenue bonds. The estimated initial financing requirement is based on the assumption that the cost to acquire the electric facilities from PSE is two times the estimated OCLD value of the facilities. Other costs we have included in the initial financing requirement are the costs of installing equipment to meter wholesale power purchases at the substations, purchase necessary vehicles and equipment, purchase materials and supplies, pay the costs of additional warehouse and maintenance facilities that the City may need and pay initial legal, engineering and consulting fees.

In addition to the initial costs, the fees associated with issuing revenue bonds and the establishment of a debt service reserve fund are included. For the base case of this analysis assuming initial acquisition at 2 times the OCLD value, the initial financing requirement is estimated to be $57.7 million.

Estimated Cost of Operations

Publicly-owned electric utilities generally establish rates to recover revenues through the sale of power sufficient to pay all operating expenses, taxes, and debt service as well as provide a margin from which to fund renewals, replacements and additions to the system. The total of all these cost obligations on an annual basis are referred to as the annual revenue requirement. Operating expenses of the electric system will include purchased power, purchased transmission services, transmission and distribution system operations and maintenance (O&M), customer accounting, and administrative and general expenses. It is expected that the City will initially either contract for O&M services and/or hire its own staff to perform some or all of these functions.

The most significant annual operating expense that the City's electric system will incur is the cost of wholesale power. Upon fulfillment of certain criteria primarily related to establishing ownership of its distribution system, the new utility will be entitled to purchase power from BPA as a preference customer. The City electric system can reasonably expect to purchase a significant portion, if not all, of its power supply from BPA at the priority firm power rate, also referred to as the Tier 1 power rate.

The annual revenue requirements have been projected for the first ten years of City electric system operation. Electric system operation is assumed to begin in 2020. Annual costs include the costs of power and transmission, transmission and distribution O&M, customer accounting, administrative and general expenses, taxes, debt service and an amount for renewals, replacements and additions to the system.

For the base case, the first year annual revenue requirement is estimated to be 11.3 cents per kWh. This is the average unit revenue needed to pay all costs of the system. Average revenue requirements are not specific rates. Rates will need to be adopted by the governing board of the City electric system. Rates would need to be established that would reflect the actual cost to serve certain customer classifications (i.e. residential, small commercial, large commercial).

Estimated Net Benefits

The estimated annual revenue requirements for the City electric have been compared to the estimated charges for electric service from PSE allow for an evaluation of the net benefits that electric consumers on Bainbridge Island would realize with the City electric system. With a public power utility the benefits are very long-term in that they are realized far into the future. For a new utility with a fairly high initial investment, the full level of benefits may not be realized until the initial loans are repaid. The long-term benefits are potentially many years in the future and as a result, are valued less today. Although an estimation of net benefits in the first ten years of new utility operation are presented in this analysis it is important to acknowledge that benefits would typically be greater in the future.

The estimation of revenue requirements for the new City electric system have been developed based on the assumptions and variables defined in this report. We are unaware of any detailed projections of future PSE electric rates so for the purpose of this analysis, an estimate of PSE's charges for electric service has been made.

The estimated cost of electric service with the City electric system is estimated to be slightly lower than the cost of service from PSE. In the assumed first year of operation, 2020, it is estimated that the average cost of electric service from the City system would be about 0.3 cents per kWh or 2.7% less than would be charged by PSE in that year. By 2029, the annual savings are estimated to be about 7.0%. Over the first ten years of operation, electric consumers in the City are estimated to pay approximately $13.1 million less in total for electric service with City system than they would with continued service from PSE.

Alternative assumptions to the analysis would result in different results. Key variables include the estimated cost of acquisition, the estimated cost of financing, and assumed increases in the number of electric customers served and load growth on Bainbridge Island. The net benefits of City service using alternative assumptions have been estimated and indicate that the purchase price and the cost of financing are significant variables. If the initial acquisition price of the facilities was 1.35 times OCLD the first year average revenue requirement would be 10.8 cents per kWh and the net savings over the first ten years of operation are estimated to be $23.0 million.

It is important to note that if so desired, a public power utility can set its rates to recover additional revenue to fund investments in expanded energy efficiency programs, development of alternative generating resources and improvements to the electric system, among other things.

Other Factors

An important advantage of a City electric utility is local control. This is especially true when it comes to socially responsible initiatives. That is, the City will be in better touch with the needs of its residents than almost any other organization and can adjust programs for the unique mix and needs of Bainbridge Island residents. Many consumer-owned utilities provide discounts to low income residents and seniors.

A number of opportunities related to a municipal electric utility exist such as the potential to develop and finance a City-owned high-speed broadband network to serve residents and businesses. There are also many opportunities for promoting and assisting in the expansion of energy efficiency programs in the community. A variety of non-economic benefits and synergies are presented in this report.

Next Steps

The primary actions to be taken at this time include reviewing and revising the feasibility report, and determining if further action towards establishment of a consumer owned utility is desired. Public discussion and input to the decision should be encouraged. The type of consumer-owned utility will need to be defined as well. Discussions with the City's legal and financial advisors should also be conducted.

If a decision is made to pursue establishment of a utility it will be necessary to prepare for a public referendum. For a PUD a vote must be taken in an even numbered year. For a municipal utility the vote can be in any year. It may be necessary to prepare additional analytical materials and information for voters.

Activities that will follow public approval will include conducting detailed discussions with BPA regarding power supply, transmission and interconnection contracts and issues. Discussions with PSE will also need to be conducted regarding the negotiations for acquiring the electric facilities. As the process progresses, discussions with vendors, contractors and others that will be needed to assist the new utility in its initial operation will need to be conducted.

Section 1
Introduction

Introduction

Background

The City of Bainbridge Island, Washington (City) retained D. Hittle & Associates, Inc. (DHA) in 2016 to conduct an electric utility municipalization feasibility study. The study is intended to provide a preliminary review of the technical and economic issues related to the establishment of an electric utility owned and operated by the City. The content of this study addresses issues defined in the scope of work agreed to between the City and DHA. This report summarizes the results and findings of the feasibility study. The law firm of Gordon Thomas Honeywell assisted DHA in the preparation of certain portions of this report.

Although the primary focus of the study has been to evaluate the feasibility of establishing a municipal utility, other forms of consumer-owned utilities such as a public utility district or an electric cooperative have been evaluated. Additional information has been provided regarding whether or not establishing a municipal utility would open up currently unavailable opportunities for local control over energy sources serving Bainbridge Island that could foster economic development, decrease greenhouse gas emissions, increase system reliability and improve power quality.

Electric service is presently provided to the residents and businesses on Bainbridge Island by Puget Sound Electric (PSE), a privately-owned electric utility headquartered in Bellevue, Washington. PSE has indicated that approximately 12,300 electric customers are served in the City. Electric facilities on Bainbridge Island include about 14 miles of 115-kilovot (kV) overhead transmission lines, three distribution substations and 307 miles of distribution lines of which 165 miles are underground. Power is delivered to Bainbridge Island from PSE's transmission network in Kitsap County and beyond by means of overhead transmission lines at Agate Pass. This overhead transmission crossing is essentially new having been rebuilt in 2014. PSE provides electric service in the City pursuant to a fifteen year franchise agreement that expires in 2022 (Ordinance No. 2007-11).

In general, the concept of establishing a municipal electric utility would involve acquisition of the existing distribution and transmission system in the City, contracting for a supply of electric power and establishing the capability to operate and maintain the electric system. Although most electric utilities retain their own staff to operate their respective systems many operation and maintenance functions can be performed by contractors if desired. PSE uses a contractor to perform most of the maintenance work on its system.

As a "publicly-owned" electric utility, if established and after meeting certain criteria, the City's municipal electric utility would be able to purchase electric power from the Bonneville Power Administration (BPA) at BPA's most favorable rate. BPA is a federal agency that markets the power from the federal Columbia River power system. Most of the publicly-owned electric utilities in the Pacific Northwest purchase most or all of their power supply from BPA. BPA also operates an extensive transmission system in the Pacific Northwest and delivers power to its customers.

In preparing this feasibility study we have reviewed the existing electric facilities in the City, identified the facilities that the City would need to establish electric service as a City electric system, estimated the costs to acquire these facilities and estimated that costs to operate, maintain, manage and administer an electric utility. Total power requirements in the City were estimated to determine how much power would need to be purchased. The annual revenues that the City electric system would need to collect for electric service to pay the costs of electric service have been estimated for several years into the future. This revenue requirement has been used to provide an estimate of electric rates the City system would charge. Comparing these estimated rates to those estimated for PSE provides an estimate of the net benefits or costs of the City electric system.

There will be many decision points if the City moves toward establishing an electric utility. Changes in the basic economic and technical factors and assumptions used in this analysis should be evaluated as they become known. Public input to the concept is also important. If it is determined that the City wants to proceed towards establishment of an electric utility, the next major steps will be to conduct discussions with BPA regarding a power purchase and transmission services contract, determine through negotiation or litigation what facilities will be acquired from PSE and what price will be paid for the facilities, determine what additional facilities should be constructed, arrange for financing, implement an organizational start-up plan and retain necessary staff, equipment and materials to provide service.

A key schedule constraint to providing electric service will be BPA's notice period related to obtaining a power sales contract for a new utility. A full requirements purchase of BPA wholesale power at BPA's lowest Tier 1 rate would normally take approximately three years depending on when the application is made relative to the BPA rate cycle. Tier 2 power could be purchased prior to that, however.

As a point of reference on the time required to establish an electric utility the experience of the most recently formed electric utility in the state, Jefferson County PUD, can be considered. The voters of Jefferson County authorized the Jefferson County PUD to provide electric service in November 2008. Jefferson County PUD negotiated with PSE on the purchase of assets and began providing electric service in April 1, 2013. This represents a planning and implementation period of approximately 53 months. Of this time approximately 19 months elapsed prior to the signing of an asset purchase agreement with PSE. The City of Hermiston, Oregon undertook an initial feasibility study related to providing municipal electric service in 1996. The acquisition of electric facilities from PacifiCorp was negotiated and the City began providing electric service on October 1, 2001, representing about a five year period in preparation of providing service.

Study Methodology

Most of the data used in the study is from publicly available reports and other sources. The City requested certain information from PSE in October 2016 and a limited amount of requested data was provided by PSE. Other information comes from public records associated with PSE, Kitsap County, the State of Washington Department of Revenue, the Washington Utilities and Transportation Commission, and selected statistics on electric utilities compiled by the Washington PUD Association and the Northwest Public Power Association, BPA, etc. Information regarding financing options and costs was obtained from financial advisors involved with the financing of electric utility systems.

PSE provided an estimate of the total number of customer accounts served in the City. The total power requirements of the electric customers in the City at the present time have been estimated based on typical energy consumption values for PSE customers as found in recent FERC Form 1 filings for PSE.

For the purpose of this study, the determination of electric facilities to be acquired was based on a cursory field examination of PSE's transmission and distribution system in the City. The length of transmission lines was estimated as were the number and capacity of substations. The estimated costs of transmission lines, distribution lines, service drops, meters and other distribution facilities, were developed using estimated unit costs based on our experience with similar utility systems.

Should the City decide to move forward in the development of a municipal utility, a much more detailed assessment of electric facility quantities and costs would need to be derived in subsequent studies and analyses. If the development of the City's electric utility proceeds and access to PSE's customer sales and facility inventory records can be obtained, a detailed inventory and age identification of various PSE assets within the City would potentially be developed.

The estimated costs the City would experience for power purchases, system operation and maintenance, customer accounting and administration included in the analysis have been based on representative costs experienced by other publicly-owned electric utilities in the Pacific Northwest. It is assumed that the City would conduct its own billing and accounting activities and would provide in-person customer service for bill paying, hookup requests and other services. These billing and accounting functions could be integrated with other City functions. In addition to operating expenses, annual debt service payments and funds for annual capital improvement expenditures were included in the projected revenue requirements

Section 2
Electric Utility Options and Other Significant Issues

Consumer-Owned Electric Utility Options

Consumer-owned electric utilities, often referred to as public power utilities, are common in the Pacific Northwest and across the United States. They provide all functions of electric service and are directed by board members, commissioners or city council members generally elected from within the service area of the utility. As such, local control is a significant element of public power utilities[1].

Public power utilities provide electric service at cost and are not-for profit, and with the exception of cooperatives do not pay federal income taxes. They generally have access to loans at tax-exempt interest rates or to loans provided by the federal government at low interest rates. Public power utilities also have preference over private utilities in purchasing low cost power generated at federal hydroelectric resources. In the Pacific Northwest, this is a significant benefit in that most public power utilities, other than those with significant generating resources of their own, purchase all, or nearly all, of their power supply requirement from the Bonneville Power Administration (BPA), a federal power marketing agency.

Rates for electric service for public power utilities are established by each utility's governing board to collect revenues sufficient to pay operating costs, pay interest and principal on debt, and pay for the renewal, replacement and additions to its facilities. Generally, public power utilities are not regulated by their respective state utility commissions. In the Pacific Northwest there is significant coordination among public power utilities to assist each other with training, group equipment purchases, representation in wholesale rate and other regulatory issues and in emergency repairs. Public power utilities often work together to develop jointly-owned or joint-power purchaser generating facilities that in themselves would be too large for smaller systems.

The three primary forms of consumer-owned electric utilities are municipal utilities, cooperative utilities and public utility districts (PUDs). Each of these utility types have certain benefits and drawbacks. They are discussed in more detail in the following subsections.

Municipal Electric Utility

Municipally-owned electric utilities are common in Washington as well as around the country. With a municipal electric utility, the city or town council typically serves as the governing board for the utility and provides oversight and approval of the utility operation, establishes rates for electric service and approves various policies and procedures. The financing authority of the municipality is used to provide funding for the acquisition and construction of necessary electric facilities; however, security for repayment of loans can be specifically limited to the revenues of

[1] The American Public Power Association (APPA) provides an overview of the benefits of municipalization in the booklet, Public Power for Your Community, available at:
http://www.publicpower.org/files/PDFs/Summary_of_Public_Power_for_Your_Community.pdf

the electric utility operation. Various administrative functions of the municipal utility, such as billing, accounting, human resources, and financial management, are often integrated with other municipal activities. The service area of most municipal electric utilities is reasonably consistent with the municipal boundary. Examples of municipally-owned electric utilities include: City of Seattle, City of Blaine, City of Sumas, City of Ellensburg, City of Tacoma, City of Ruston, Town of Steilacoom, City of Port Angeles, City of Centralia, and the City of Richland.

Some cities, such as first class or code cities, have authority to provide retail telecommunication services.

For a municipal electric utility, planning, engineering and construction can be coordinated within the municipality as a joint effort among the various municipal operations. This can be very helpful with regard to comprehensive planning and in building and maintaining the electric system to address a municipality's broader goals. For example, undergrounding of electric lines can be effectively coordinated with street construction or water and sewer system improvements.

An advantage of a municipal electric utility is the ability to obtain financing for most capital expenditures at tax-exempt interest rates. A municipal utility does not pay federal income taxes and its revenues can be used to pay the costs of certain services provided to the utility through the municipal government. Municipal utilities are required to pay the state public utility tax and most municipal utilities collect a local tax on power sales as well. Municipal utilities have condemnation authority.

Although the city council serves as the governing board of a municipal electric utility, some municipal utilities establish boards to provide more of the regular oversight of the electric utility and formulate recommendations for the city council. These boards in some instances have been delegated authority for certain defined decision-making, and in other instances are solely advisory in nature. City councils are responsible for much more than the oversight of utility operations and the use of a utility advisory or other board can be of significant assistance. More information on the function of advisory boards is provided in the subsection entitled "Alternative Municipal Governing and Advisory Concepts" in this report.

The time required to establish a municipal electric utility could be relatively short; however, it may require an extended period of discussion before the city council. The time required is very much dependent on the willingness of the incumbent utility to sell the existing electric facilities. In Washington, RCW 35.92.070 requires approval of a majority vote of the voters of the city if the governing body of the city deems it advisable to acquire a public utility. The vote can be conducted at any general or special election, requires thirty days prior notice and requires a simple majority for approval. In addition, the ordinance submitted to the voters for approval or rejection is required to specify the proposed plan and declare its estimated cost. As such, it would be necessary to have a fairly well established plan for the new municipal utility operation before conducting the vote.

A new municipal electric utility would need to qualify for the purchase of BPA power pursuant to BPA's requirements for new preference customers.

Public Utility District

Public utility districts (PUDs) are nonprofit, consumer-owned utilities that provide electricity, water, wholesale telecommunications and sewer service. The citizens in each Washington county have the right to form a PUD. In Washington, there are 28 operating PUDs in 27 counties which in total provide electric service to approximately 1,003,000 customers and water service to approximately 122,000 customers in their respective service areas. Counties can have more than one PUD as is exemplified with two PUDs in Mason County.

Kitsap County PUD was organized in 1940 and provides water service to approximately 14,000 customers in various locations within Kitsap County including Bainbridge Island. In 2000, Kitsap County PUD began providing wholesale broadband telecommunication services in the county. Kitsap County PUD does not presently provide electric service but has considered the possibility of doing so in the past.

PUDs are governed by a board of commissioners typically consisting of three commissioners elected from the residents of the county in which the PUD is located.

The formation of a new PUD in Kitsap County could be undertaken in conjunction with the county government. RCW 54.08.010 provides that at any general election in an even-numbered year, the county legislative authority may conduct an election (and on petition of 10% of the qualified voters is required to conduct an election) to approve formation of a PUD coextensive with the boundary of the county.[2] The petition must be filed with the county auditor not less than four months before the election. Further, the form of the petition has to be submitted to the county auditor within ten months prior to the election.

It is also permissible to establish a PUD that covers less than the entire county. In this circumstance, a petition is filed with the county legislative authority and a hearing is held after public notice and boundaries of the PUD will be established. If the county finds the petition includes lands improperly or which will not be benefited by the PUD, it will change the boundaries of the proposed PUD and fix them as it deems reasonable and that are "just and conducive to the public welfare".[3] The partial county area cannot divide any voting precincts. The election is confined to the area of the proposed PUD.

At the same election requesting approval to form a new PUD, there will also be held an election of three commissioners. If the proposition to form the PUD does not receive approval by a majority of the voters, the election of the new commissioners is declared null and void.

Another PUD option would be to pursue electric service through the existing Kitsap County PUD. Pursuant to RCW 54.08.070, any PUD which has been in existence for at least ten years and does not currently provide electric service must conduct an election in the PUD service area to obtain

[2] Under RCW 54.08.060, the county legislative authority may also call a special election for this purpose at the earliest practicable time, and at the request of the petitioners must do so.
[3] RCW 54.08.010, Districts including the entire county or less – Procedure (Effective January 1, 2007.)

voter approval to do so. The election must be held in an even-numbered year and may be submitted to the voters of the district by PUD commission resolution, and must be submitted to a vote based on a petition of 10% of the voters in the PUD area submitted to the county legislative authority at least four months prior to the election date and within 10 months before the election.

The acquisition of electric facilities from PSE by a PUD would be accomplished similar to that of a new municipal utility, although there are a few differences outlined in RCW 54. The PUD would have condemnation authority and could exercise this authority if an acceptable sale of the facilities could not be negotiated. Electric service through the PUD would not need to be provided to all county residents. A plan would need to be developed to assure reliable, cost effective service to all county residents.

An existing PUD that establishes electric service would be viewed by BPA as a new electric utility as far as access to preference power is concerned. As a result, the issues and timing associated with access to BPA power would be the same for a new municipal electric utility or the existing PUD. The PUD would also need to start a new electric utility operation similar to that of the municipal electric utility.

Electric Cooperative

An electric cooperative is a non-profit corporation tasked with providing electric service to its members residing in a specific service area. Revenues in excess of expenses are either reinvested in the system for improvements and replacements or are distributed to members in the form of "capital credits". There are fifteen electric cooperatives[4] in Washington providing electric service to approximately 158,000 member-customers. Generally, electric cooperatives provide service in rural areas. This was the intent of the Rural Electrification Administration (REA) which was created in 1935 to promote the extension of reasonably priced electricity to farms in areas not served by existing electric utilities. Under the Department of Agriculture Reorganization Act of 1994 the REA was absorbed by the Rural Utilities Service (RUS). It is noted, however, that several smaller towns and cities in Washington, including Prosser, North Bend and Gig Harbor, are within the service areas of electric cooperatives.

Most electric cooperatives obtain low interest loans from the federal government through the Rural Utilities Service (RUS), a government agency within the U.S. Department of Agriculture. The low interest loans are generally only available to fund costs related to the rural portions of the utility. This means that the costs of the urban portions of the system may need to be funded with other sources. Electric cooperatives do not have access to tax-exempt financing like municipal utilities and PUDs and, as a result, the average cost of capital for electric cooperatives is generally higher than for PUDs and municipalities. In addition to loans through the federal RUS, there are also two lending entities, CFC and Cobank that offer lower cost loans to electric cooperatives.

[4] Includes mutual and cooperative utilities, which function much the same, headquartered in Washington. There are also three other electric cooperatives that serve member-customers in Washington that are headquartered in Idaho.

Cooperatives are governed by a board of directors elected from the membership. The board of directors sets policies and procedures that are implemented by the cooperative's professional staff. Membership in the cooperative is voluntary. An electric cooperative could be established in Kitsap County by any group interested in doing so. To provide electric service in the area however, a sufficient number of members would need to be identified and committed to form the base for acquiring electric facilities, contracting for power and starting a utility operation. A cooperative does not have condemnation authority and would need to negotiate with PSE to acquire the PSE electric facilities.

Another alternative is to request to become part of an existing cooperative. Cooperatives do not need to have a contiguous service territory. For example Tanner Electric Cooperative has three service territories near Ames Lake, North Bend and Anderson Island.

Electric cooperatives, like municipal utilities and PUDs, are not regulated by the Washington Utilities and Transportation Commission (WUTC). The WUTC has no jurisdiction over a cooperative; however, it would be expected that the WUTC will provide some review of the proposed transfer of electric service from a regulated utility such as PSE to the cooperative on behalf of electric consumers.

There are no particular time requirements related to establishing a cooperative. Schedule requirements related to acquiring a power supply would be similar to a municipal utility and a PUD. A membership campaign would be needed and it is expected that approximately one to two years would be needed to negotiate the purchase of electric facilities and conduct various engineering studies.

Comparison of Consumer-Owned Utility Options

The following table summarizes the primary differences of utility ownership options.

TABLE 1
Comparison of Consumer-Owned Electric Utility Options

	Municipal Electric Utility	Public Utility District (PUD)	Electric Cooperative
Governing Board elected by local voters?	Yes	Yes	Yes†
Governed locally?	Yes	Yes	Yes
Board meetings generally open to the public?	Yes	Yes	Yes
Access to tax-exempt financing?	Yes*	Yes*	No
Non-profit entity?	Yes	Yes	Yes
Rates generally established at cost?	Yes	Yes	Yes
Required to pay income taxes?	No	No	No
Equity in electric facility assets generally accrue to customer/owners?	Yes	Yes	Yes
Access to BPA Tier 1 power at preference rates?	Yes	Yes	Yes
Regulated by Washington Utility and Transportation Commission?	No	No	No

* Tax-exempt financing is generally not available to pay the costs of acquiring electric facilities of an existing utility.
† Governing Board is elected by Cooperative members.

Alternative Municipal Governing and Advisory Concepts

As previously mentioned, the governing body for a municipal electric utility is the city council. As such, the city council provides general oversight of the utility, retains competent management, makes policy decisions and sets the rates and charges for utility service. City council members are elected by the citizens within the municipality and as a result, the governing board of the electric utility is elected by the citizens.

Some city councils have established utility boards or utility advisory committees to provide a more specialized oversight of the utility operation, review recommendations of utility management and staff and advise the city council with regard to various issues related to utility policy, operation and administration. Typically the members of a utility board are appointed by the city council.

The advisory boards have a variety of functions to perform but generally they are expected to have regular contact with the electric utility management and the general public and assist the city council in administering the utility, establishing policy and addressing utility-related issues of concern to electric consumers and the community as a whole. Serving as the utility governing board is just one of many tasks performed by a city council and a utility board or advisory committee can remain focused on the utility business and provide significant coordination between the utility and the city council.

Examples of utility boards in Washington include:

Tacoma Public Utilities (TPU), Public Utility Board

The five-member board oversees the operations of Tacoma's electric and water utilities, the Click! communications operations, and industrial freight-switching railroad. The Tacoma City Council appoints the board members and they serve five-year terms, unpaid. The board meets twice monthly and board meetings are open to the public for public comment.

Seattle City Light, City Light Review Panel

The Seattle City Light Review Panel was created in 2010 as the successor to the City Light Advisory Board/Committee and the Rate Advisory Committee, and combines the duties of both groups.

The nine panel members come from City Light’s customer groups. Five members are nominated by the mayor and four members are nominated by the city council, serving staggered three-year terms. In 2010, the focus of the panel was to help develop a six year strategic plan for Seattle City Light.

City of Ellensburg, Utility Advisory Committee

There are seven Utility Advisory Committee members consisting of two city council members, one representative from Central Washington University, two customers of one or more city utility systems, one representative of KITTCOM and one customer of the telecommunications utility. Committee members serve three-year terms. The committee meets monthly.

The Utility Advisory Committee operates under the authority of the Ellensburg city code and was created for the purpose of providing a mechanism for the city council to obtain benefits of recommendations, advice, and opinions on those matters affecting City energy policy and operations from a committee which may devote the resources necessary for careful consideration of such matters and which will increase citizen participation and input to local government.

City of Port Angeles, Utility Advisory Committee

The Utility Advisory Committee gives advisory recommendations to the City Council on matters relating to city utility policy and operation.

The Utility Advisory Committee is comprised of three City Council members, one industrial representative, and two community representatives. The members are appointed to four-year terms, with a limit of two consecutive terms. Members are residents of the city, except the member representing the licensed care facilities need not be a city resident but must own or manage a licensed care facility in the city.

Eugene Water and Electric Board (EWEB

EWEB is chartered by the City of Eugene, Oregon to serve as the electric and water utility providing service to the homes, businesses, schools and other customers in Eugene. In accordance with the Eugene city charter, the citizens of Eugene elect a five-member Board of Commissioners for EWEB. Four board members represent specific wards within the city; the fifth member is elected "at-large" by all city voters. Each commissioner's term is four years.

Commissioners hold regularly scheduled public board meetings on the first Tuesday of each month. The opportunity for public comment is provided at each board meeting.

Acquiring Electric Facilities

If a new public power utility were to be established on Bainbridge Island it would be necessary for the new utility to own its electric distribution system in order to purchase power from BPA as a preference customer. It is expected that the existing electric facilities currently owned by PSE on Bainbridge Island would be acquired or replaced by the new utility. PSE would need to be paid a fair value for the electric facilities. To establish the value of the existing facilities the facilities will need to be inventoried, assessed and quantified and a valuation estimate will be developed. Engineering analysis will be needed to determine how the new utility will operate its facilities separate from the surrounding PSE system and determine where wholesale power deliveries will be received.

A separation plan must be prepared that could include the specification of new transmission, distribution and operation facilities. In some cases the separation plan is implemented by agreement over a period of time that extends beyond the ownership transfer date[5].

The purchase of the electric facilities by the new utility can be relatively straightforward if both parties are cooperative. Without cooperation, condemnation could be utilized for acquisition. A condemnation process can be time consuming and costly, but could provide a path to municipal electric utility formation with an unwilling seller. Overall, we would estimate that the time needed to acquire the electric facilities would require between one and three years, with the shorter time reflective of a relatively simple negotiated sale and the longer period reflective of an aggressive condemnation proceeding that includes appeals.

Prior to establishing electric service in Jefferson County in 2013, Jefferson County PUD negotiated with PSE to purchase the electric facilities in the county owned by PSE. The PUD chose to negotiate a purchase price rather than pursue acquisition through the condemnation process. The condemnation process could have potentially produced a lower purchase price but most likely would have taken longer to complete. With condemnation, the price to purchase the electric facilities is specified by the court proceedings.

The City of Hermiston, Oregon is an example of a new public power utility established in 2001 that pursued its option to condemn the electric facilities owned by PacifiCorp but eventually agreed to a negotiated acquisition settlement.

The City has the authority to condemn the property of PSE within the City municipal boundaries. If the City elects to condemn the property prior to forming a PUD, its authority is pursuant to RCW 35.92.050. If the City elects to form a PUD first, the PUD has authority to condemn pursuant to RCW 54.16.020. Eminent domain proceedings are entirely statutory and the procedures for such proceedings are set forth in Washington Revised Code Sections 8.04.005 to -8.28.070.

[5] Emerald PUD in Springfield, Oregon had a net billing arrangement with Pacific Power & Light that allowed certain customers to be served off the other utility's lines while new facilities were constructed. The arrangement was in effect for well over 20 years.

There are two circumstances in which the City or a PUD might undertake to condemn PSE's facilities. If PSE is not willing to voluntarily sell the facilities, then it will be necessary to invoke its power of eminent domain to compel the acquisition. Even if PSE is willing to negotiate and sell voluntarily, the City may still elect to commence a condemnation action if the parties cannot reach agreement with regard to a purchase price. Through the condemnation process the City may or may not achieve a lower acquisition cost than it could through a negotiated sale. The City should consider the costs, time frame, and risks of litigation when evaluating acquisition costs in the context of a condemnation proceeding.

The estimated cost for the City or a PUD to condemn the PSE electric facilities in Bainbridge Island is difficult to predict. But if litigation is pursued, the City should assume that the cumulative attorneys' fees and expert costs can be expected to be in the seven figure range.

The estimated time needed to reach conclusion of acquiring PSE's facilities through condemnation from the date of filing the petition through trial is between 12 and 24 months. This is exclusive of appeals. An appeal will not delay obtaining possession of PSE's property, provided that the City or PUD pays in full the judgment as awarded by the jury or judge pending appeal.

Examples of Recent Public Power Utility Acquisitions in the Pacific Northwest

As previously indicated, in 2010 Jefferson County PUD negotiated to purchase the PSE electric facilities in Jefferson County thereby avoiding the condemnation process. The negotiated purchase price for the facilities was $103 million[6]. In WUTC's order[7] regarding the matter of PSE's petition for accounting of the proceeds from the sale of assets to Jefferson County PUD, the WUTC indicated that the net book value or original cost less depreciation (OCLD) of the assets was $46.7 million. Based on this net book value amount, the negotiated purchase price was approximately 2.2 times the net book value.

In 2001, the City of Hermiston, Oregon negotiated to purchase the electric facilities in Hermiston from PacifiCorp. The estimated purchase price was $8.1 million, estimated to be about two times the net book value of the electric facilities. At the time, the purchase price represented approximately $1,670 per electric customer account in Hermiston.

In 2000, the Columbia River People's Utility District headquartered in St. Helens, Oregon, acquired certain service territory and electric facilities owned by Portland General Electric Company (PGE). The service area acquired in 2000 included portions in the incorporated towns of St. Helens, Scappoose, Rainier and Columbia City that PGE had continued to serve after the PUD began electric service in 1984. The PUD paid PGE approximately $9.5 million for the electric distribution facilities in the acquired area in 2000, representing about $1,580 per electric customer account in the acquired area.

[6] Actual proceeds of the sale were $109.3 million.
[7] Washington Utilities and Transportation Commission, Docket UE-132027, Order 04, Service Date September 11, 2014.

Power Supply Overview

As with most Pacific Northwest electric utilities, the most significant annual operating expense that the City's electric system will incur is the cost of wholesale power. For many public power distribution electric utilities, purchased power and transmission expense typically represents 40-60% of the annual budget. Upon fulfillment of certain criteria primarily related to establishing ownership of its distribution system, the new utility will be entitled to purchase power from the Bonneville Power Administration (BPA) as a preference customer. BPA principally markets the power generated by the Federal Columbia River Power System (FCRPS), which is comprised mostly of the hydropower generated at federal dams. The City electric system can reasonably expect to purchase a significant portion, if not all, of its power supply from BPA at BPA's lowest cost of power, which is the priority firm power rate, also referred to as the Tier 1 power rate.

In addition to BPA, a number of other opportunities for near-term power supply could be available to the City including power purchases from other utilities, independent generating facilities or power marketers. In the future, it is expected that the City will most likely continue to purchase power from BPA but will also be able to participate jointly with other utilities in new generation facilities, contract to purchase power from other suppliers and construct new generating facilities of its own including solar, wind and other renewable resources. For our initial analysis, we have assumed that the full power requirement of the new utility is supplied by BPA wholesale power.

BPA Power Supply Contract Issues

BPA is a federal agency within the Department of Energy that markets electric power from federal hydroelectric projects and certain other facilities to the region's utilities. Most of the publicly-owned electric utilities in the Pacific Northwest rely upon BPA for a significant portion of their power supply needs. As a municipal electric utility, the City's electric system would be able to contract with BPA to purchase its power supply from BPA provided certain criteria are met. Further, the City's system should qualify to purchase the majority of its power requirement at BPA's lowest wholesale power rate.

One of BPA's long standing standards for purchasing Federal power requires a customer to own the distribution facilities necessary and used to serve such customer's retail consumers. This standard applies to public body, cooperative, and privately-owned utilities selling to the general public and to federal agencies.

In July of 2007, BPA published a Long Term Regional Dialogue Final Policy and the Record of Decision on the policy was issued in October 2008[8]. The policy addressed issues necessary to begin negotiating and offering new power sales contracts for service after 2011, defined the products and services BPA would offer in those contracts, and described the process for designing

[8] Bonneville Power Administration, Long-term Regional Dialogue Policy, Administrator's Record of Decision, October 31, 2008.

and establishing a tiered Priority Firm (PF) power rate methodology. In particular, the policy stated that BPA intended to execute new long-term power sales contracts with its regional customers and discussed in some detail service to existing and new preference customers.

The current long-term power sales contracts have been offered and provide for the purchase of BPA power between fiscal year (FY) 2012 (beginning October 1, 2011) and FY 2028. These contracts are complex, but allow for new preference customers, such as the City to be formed and receive power under certain terms and conditions. The Regional Dialogue specifically references new public utilities that serve what were previously privately -owned utility customers. BPA refers to this as "annexed loads" of new preference customers.

A significant element of the long-term contracts BPA entered into with its public power customers provides for tiered rates. Tier 1 power, BPA's lowest cost wholesale firm power product, is limited to the output of the federal system with some augmentation. Each utility has a contract high water mark (CHWM) that is used to establish the allocation of Tier 1 power and the amount of Tier 1 power each utility can receive. The amount of Tier 1 power provided to each utility can change throughout the contract period, which ends in 2028, and if additional power is needed utilities can supplement their Tier 1 power allocations with Tier 2 power, power from other generating facilities, or other power purchases. BPA will also act on behalf of a utility to make other purchases and provide ancillary services to integrate those purchases for the utility.

BPA's policy to serve new public power customers provides (based on current resources) for up to 250 average megawatts of power for new customers during the current long-term contract period. The CWHM for new customers is established as the total net requirement of the new utility in the first year of service. Some limitations do apply, however, in that during any two-year rate period, the amount of power available to new customers is limited to 50 average megawatts. If necessary, individual CHWM amounts for the new utilities will be prorated down to remain within the 50 average MW limit. If this limit is applied, the amounts not provided in the first year will be added in the next rate period. Another limitation is that utilities with loads larger than 10 average MW would potentially have their CHWM over 10 average MW phased in over two-year increments if there is more than one new utility and their combined CHWM exceeds the 50 average MW limit.

Over time BPA has established certain criteria that must be met before an entity may qualify for service from BPA[9]. For a new preference customer, such as the City to comply with the existing standards for service, it must:

1. Be legally formed in accordance with state and federal laws;
2. Own a distribution system and be ready, willing and able to take power from BPA within a reasonable period of time;
3. Have a general utility responsibility within the service area;

[9] Bonneville Power Administration, Final Policy on Standards for Service – Administrator's Record of Decision, December 22, 1999.

4. Have the financial ability to pay BPA for the federal power it purchases;
5. Have adequate utility operations and structure; and
6. Be able to purchase power in wholesale, commercial amounts.

Upon compliance with these standards for service and upon application to BPA under the provisions of Section 5(b)(1) of the Northwest Power Act, the City will be entitled to purchase power from BPA as a preference customer.

At the present time it is estimated that approximately 200 average MW for new public power customers still remains in the current contract period. The only new public power utility to form and contract with BPA during the contract period has been Jefferson County PUD, with a CHWM just under 50 average MW. If the City were to apply for a contract with BPA and meet the notification requirements and there are no other concurrent new utility applicants, it is expected that the City's full load requirement for the electric system could be established as the CHWM in the first year of service.

The cost of BPA power to the City will be governed by the BPA Power Sales Contract and various other BPA policies. New large loads, such as a large commercial customer, over 10 average MW that are placed on BPA's system may be subject to a surcharge related to the cost of power supply, potentially at market rates that BPA may need to acquire on behalf of the new load. In the case of the City, there are no anticipated new large loads.

For the purpose of estimating the cost of power to the City in this analysis, it has been assumed that the City would purchase its entire power supply requirement from BPA. Under current BPA policy and past BPA precedents, a power purchase from BPA would entail both Tier 1 power and historically more expensive Tier 2 or market priced power. Currently market priced power is at about the same price or in some cases lower than Tier 1 power from BPA. To be conservative we have assumed that BPA Tier 2 power is 15% more expensive than BPA Tier 1 power.

BPA's Resource Mix

For its preference power customers, BPA does not identify specific resources for specific sales. Rather, the "mix" of BPA's power resources is used to establish the overall power product. For its fiscal year 2014, BPA indicates that the mix of its resources by generation type is as follows:

- Hydroelectric 83.3%
- Nuclear 10.4%
- Non-specified purchases 4.4%
- Small hydro and wind 1.9%

Since the vast majority of BPA's power is from hydroelectric resources, power generation varies each year based on regional precipitation and other factors. In years with more generation in the system, power surplus to the needs of firm commitments may be marketed at lower prices. This makes it difficult to determine whether or not there is actually firm power regularly available to meet the needs of a new customer in any given year. BPA has noted that in 2014, 12% of its total revenues came from sales of power to public and investor-owned utilities in the Southwest and California.

If the City were to become a new customer of BPA it could be that BPA's sales outside the Pacific Northwest region might be slightly reduced in some years when hydroelectric generation is lower. This is a complex topic as the FCRPS is operated on a dynamic basis. With an added new BPA customer such as the City, the FCRPS will have less electricity at times to export out of the region, principally to California where it displaces partially fossil fueled generation. At other times, say during high Pacific Northwest wind turbine power production, sales to a new BPA customer would reduce the amount of water spilled over dams. Similarly, when there is limited transmission capacity to California and high generation there may be no reduction in exports to California. Furthermore, because City customers are already served principally by existing Pacific Northwest generation, the "net" load of PSE plus BPA would not change, Therefore, the reduction on the amount of future energy that would be exported out of the Pacific Northwest and would potentially decrease fossil fuel generation emissions outside the region would likely be small to non-existent.

Other Power Supply Options

Although most of the smaller public power utilities in the Pacific Northwest purchase their full power requirement from BPA, there are many options currently available for short and long-term contract purchases of renewable and traditional power. The City could choose to pursue some of these options on its own or join with other utilities. Organizations such as The Energy Authority[10] (TEA) can be used to assist with acquisition and management of power supply resources. According to TEA there are good opportunities at the present time to purchase energy from wind farms pursuant to longer term, 10-20 year, contracts.

In addition to purchasing power from energy resources owned by others, public power utilities can jointly develop, own and operate generation projects. Energy Northwest is an example of a joint operating agency owned by 27 public power utilities in Washington. Among other projects, Energy Northwest owns and operates, the Packwood hydroelectric project near Yelm, Washington, the Columbia Generating Station, near Richland, Washington, the 64 MW Nine Canyon Wind Project located near Kennewick, Washington and the White Bluffs Solar Station, a solar photovoltaic demonstration project near Richland, Washington.

[10] The Energy Authority is a public power owned non-profit corporation with offices in Jacksonville, Florida and Bellevue, Washington. As a national portfolio management company they assist clients in obtaining and managing power supply resources.

Transmission Requirements

The new electric utility will also require a transmission contract to transmit the power it purchases to its distribution system. A typical public power utility would have a BPA transmission contract. BPA offers both network integration and point to point transmission contracts. It is assumed that the new utility will obtain a network integration transmission contract with BPA and that in conjunction with the power sales contract, BPA will deliver power over BPA's and PSE's transmission systems to a delivery point at a substation on Bainbridge Island.

Operational Reliability

Reliability of electric service has been indicated to be a key issue of concern to the residents and businesses of Bainbridge Island. Based on outage statistics provided to the City by PSE, it can be seen that tree related issues are the cause of the vast majority of customer outage minutes on Bainbridge Island. The data indicates that there were on average, 270 distribution outages per year between 2004 and 2015 of which approximately 50% are indicated to be caused by trees. Unknown causes and equipment failure represents the second and third largest causes of distribution outages. During the same period, there were about 2.5 transmission outages per year on average, most caused by trees.

The total number of distribution customer outage minutes for all Bainbridge Island customers between 2004 and 2015 averaged about 10.5 million minutes per year of which about 9.2 million minutes, or 92% were tree related.

The five-year system average interruption duration index (SAIDI) benchmark is a defined term by the WUTC. The WUTC service quality index #3 or "SAIDI-total 5-year average" is based on all customer minutes of interruptions that occurred during the current and previous 4 years, except for extreme weather or unusual events, divided by the average annual number of electric customers. PSE annually reports this information to the WUTC by county. While an important statistic for an electric utility, a more meaningful measure of service from a customer perspective includes extreme weather or unusual events.

The outage data for Bainbridge Island provided to the City by PSE can be used to develop an estimated "all in" tree related SAIDI-type of index for Bainbridge Island. Adding the "all-in" customer minutes of distribution tree outage to the "all-in" customer minutes of transmission tree outage and dividing by the number of customers provides a representative SAIDI-like statistic related to tree outages. This "all-in" statistic does not exempt major storms or events. Performing such a calculation yields the following:

Average Annual Bainbridge Island Customer Outage Minutes per Customer

	2009	2010	2011	2012	2013	2014	2015	2016 (partial year)
Distribution Tree related “all-in”	517	1,844	212	115	286	494	1,082	694
Transmission Tree related “all-in”	31	483	95	168	151	214	1,084	294
Total Tree related annual average	548	2,327	307	282	437	708	2,166	989
Total all causes “all in” annual average	655	2,497	384	392	510	819	2,336	1,110

The analysis in the above table shows that both distribution and transmission tree related outages are significant and need to be addressed if reliability is to be improved. A further evaluation of reported outage statistics in Kitsap County was also conducted for comparison.

In the March 29, 2016, PSE Service Quality and Electric Service Reliability filed with the WUTC various PSE SAIDI statistics by county for the years 2013, 2014, and 2015 are shown in Appendix K of that report. Kitsap County had the highest $SAIDI_{Total}$ value of any county in PSE’s system in 2015 (1,715 minutes), third highest county value in 2014 (607 minutes) and highest county value in 2013 (324 minutes). This report shows that in 2015 the $SAIDI_{Total}$ for all outages in PSE’s system was 760 minutes. Bainbridge Island tree-related outages appear to be at or higher in total average minutes of outage than Kitsap County total average minutes of outages for each of these years.

The reliability implications are threefold. First, tree-related outages in 2015 are the most significant reliability issue on Bainbridge Island and the tree outages appear to be much higher in terms of customer outage minutes per customer than the system-wide PSE $SAIDI_{Total}$ for 2015 reported in the WUTC reliability report. It should also be noted that $SAIDI_{Total}$ in Kitsap County during the years 2013, 2014, 2015 seems to have been higher than average $SAIDI_{Total}$ outages for PSE customers in other counties.

Second, if the City were to establish an electric utility its efforts to improve reliability should be focused. One focal point, vegetation management, will likely be a critical component. Another focal point will be the City’s ability to provide quick restoration of power after an outage, which may be enhanced if equipment and crews are located within the City. This would reduce the number of minutes of a typical outage. Still another focal point may be undergrounding of power lines in certain areas to further reduce outages. This does not mean that other forms of maintenance or system design should be neglected. If the City does not form a new electric utility, then the City may wish to focus its reliability discussions with PSE on what can be done to prevent tree-related outages and/or shortening the amount of time to restore power. To prevent tree related outages may require more information on the types of vegetation management by circuit/location and the outages in those locations.

Third, if a reduction in the SAIDI or minutes of customer outage per customer is a goal, both transmission and distribution tree-related outages will need to be addressed. This is because either can be the majority of the $SAIDI_{all\text{-}in}$ minutes in a particular year.

As another point of comparison, we also examined a Snohomish County PUD Electric System Reliability Report that included statistics from 1991 to 2015. Snohomish County is slightly north and east of Bainbridge Island and it includes rural forested areas as well as urban and suburban areas within its service territory.

In Appendix C of the Snohomish County PUD reliability report in Table C-1 of SAIDI, there is data broken out by distribution, transmission, unusual weather events, declared major events and "Overall (Everything)." The Snohomish County PUD "Overall" SAIDI is compared to the PSE Bainbridge Island "all in" total outage minutes in the following table:

Comparison of Snohomish County PUD Overall to Bainbridge Island Total Annual Average Customer Outage Minutes per Customer

	2009	2010	2011	2012	2013	2014	2015
Snohomish County PUD "Overall (Everything)" SAIDI (i.e. Trees and all other causes for both transmission and distribution)	76	114	83	116	85	229	1,390
Bainbridge Island Total All Causes "all-in" (see previous table)	655	2,497	384	392	510	819	2,336

It can be seen from the above table that there are far more average minutes of customer outage on Bainbridge Island than in Snohomish County PUD. Since tree related issues are the most significant cause of outages on Bainbridge Island, vegetation management or tree trimming is the critical reliability factor.

Snohomish County PUD performed a detailed analysis of its outages on the 20 circuits with the greatest number of distribution outages. The PUD determined that the number of tree related distribution outages, where trees or branches are farther away than 10 feet from power lines is less than the number of outages (by about a factor of slightly less than two) than where trees and limbs are closer. However, what the PUD also found was that the distant tree caused outage average customer durations (in non-major events or storms) were just slightly less (ratio of about 36 to 40) to more distant tree minutes of outage. The implication for Bainbridge Island is that to improve SAIDI, trees close to the power lines as well as those more distant need to be addressed, even though tree trimming within 10 feet of power lines is associated with the greater number of outages.

Section 3
Estimated Cost of Electric Facilities

Electric System Facilities on Bainbridge Island

Electric service on Bainbridge Island is presently provided by PSE. The electric facilities located within the City include transmission lines, substations, overhead and underground distribution lines, poles, transformers, vaults, service drops, meters, streetlights, right-of-ways and ancillary distribution system facilities. There are three substations on the island that transform power from transmission voltage to the primary distribution voltage.

PSE's transmission system on Bainbridge Island consists of approximately 14 miles of 115-kilovolt (kV) overhead transmission lines that connect to PSE's transmission system on the Kitsap Peninsula side of Agate Passage. There are two transmission circuits that cross Agate Passage by means of an overhead crossing that is essentially new, having been rebuilt in 2014. Once on the island, the two transmission circuits separate and proceed along different routes until Hidden Cove Road and Highway 305. From that point they are near each other along Highway 305 until they reach the Port Madison substation located at the northwest corner of the intersection of Day Road and Highway 305.

The Port Madison substation was originally built in 1980 and serves as a transmission switching station as well as a distribution substation serving approximately 4,000 electric customers. Two radial transmission lines proceed from the Port Madison substation, one to the Murden Cove substation and one to the Winslow substation. The Winslow substation was originally built in 1960 and serves approximately 3,800 customers. The Murden Cove substation was originally built in 1980 and serves approximately 4,500 customers. Each of the three substations has one transformer that provides power at 12.5-kV, the primary distribution voltage, to four distribution feeders.

The transmission connections at the Port Madison substation are indicated by PSE to have been rebuilt in 2000. The underground getaways appear to be older. Two of the feeder getaways at the Murden Cove substation appear to have been rebuilt with new underground cables for each circuit. The Murden Cove substation yard is large and could accommodate a second transformer if needed in the future. The Winslow substation is built using overhead getaways and the poles and wires appear to have been recently replaced. Several overhead spans from the Winslow substation in both directions use tree wire. The Winslow substation yard appears to be smaller making it difficult to expand in the future.

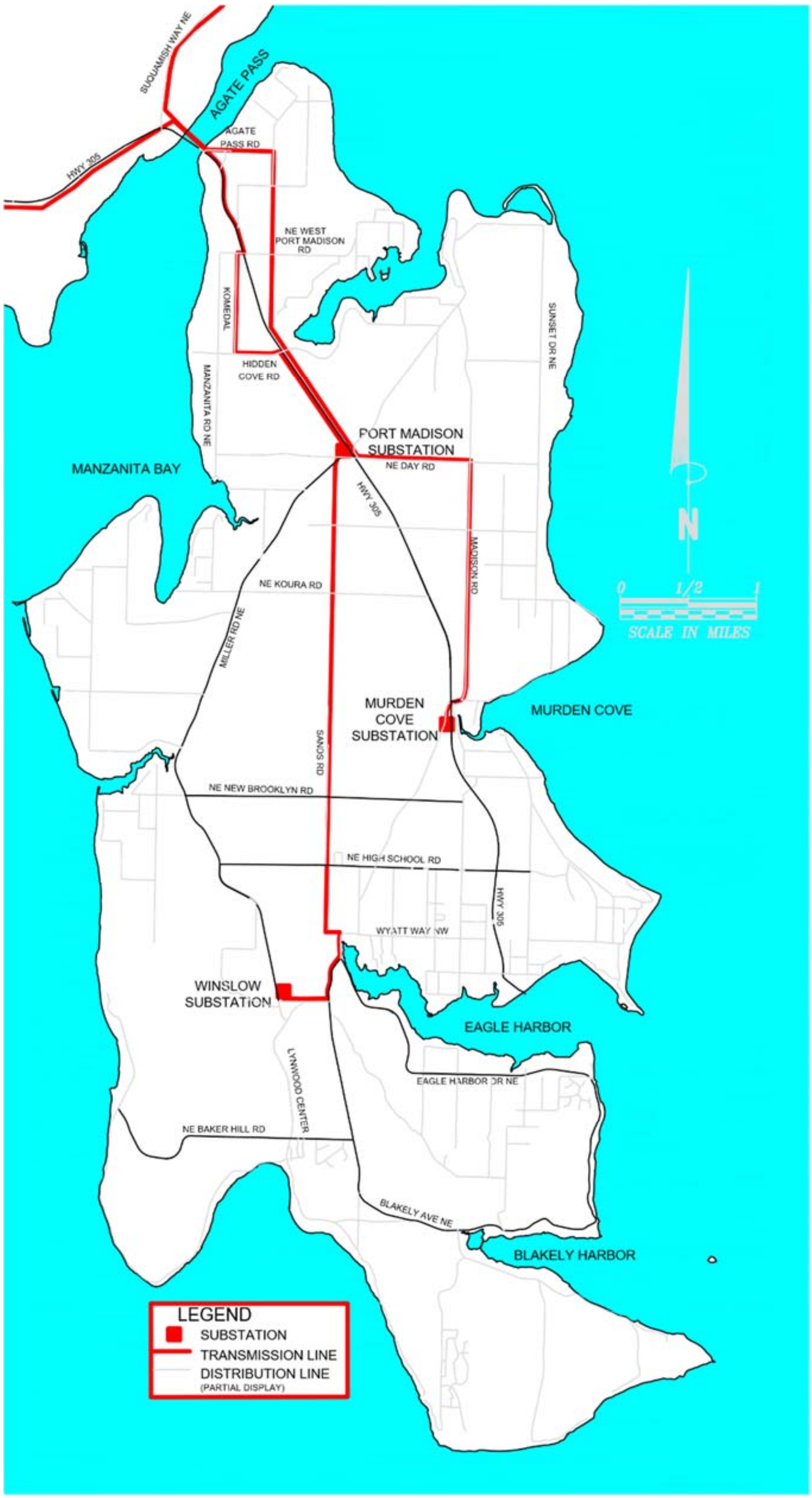

Figure 1 Bainbridge Island Transmission and Substation Facilities (*Partial representation of distribution lines*)

PSE indicates that there are 307 miles of distribution lines on Bainbridge Island of which 165 miles are underground. The overhead and underground lines are a mixture of three, two and single phase. In addition, 22 miles of overhead distribution lines use insulated tree wire. Overhead distribution and transmission lines are generally built with typical wood-pole construction and in some areas the distribution lines are underbuilt on transmission poles. The exception to the transmission is the steel pole/tower crossing of Agate Passage.

The distribution system appears to be a mixture of main feeders, some of which were rebuilt in the past few years, and many laterals and smaller feeder wire portions that are older. It was noted that some poles along Crystal Spring Drive NE are placed in the beach with anchoring extending into the tidal area. The distribution system appears to be designed and operated principally as a radial system.

Proposed Facilities to be Acquired

There are several options that the City could take in defining the electric facilities that would be acquired to establish a new electric utility system. It is expected that the substations, distribution lines, transformers, services and meters would be needed for the City to own the distribution system as required by BPA. All of the transmission lines, however, would not necessarily need to be acquired. Instead, PSE could continue to own some or all of the transmission lines on the island and BPA would make arrangements with PSE to deliver power over the lines to the City's substations.

BPA has historically even provided transmission service to and through PSE owned substations for some of its preference customers. Examples includes BPA service to the cities of Blaine and Sumas, both of which are served at primary voltages from PSE substations by BPA contract.

Alternatively, the new electric utility could acquire the transmission lines from the connection to PSE's Kitsap Peninsula transmission system at Suquamish Way NE and own the crossing at Agate Pass and all the 115-kV lines on Bainbridge Island. Another option could be to build a new transmission line from the Suquamish Way connection point to BPA's closest substation at the Bangor naval base. This line is estimated to be approximately eleven miles long and would potentially be difficult to permit and construct. It would also only provide a single radial line to the City's system from Bangor presenting a potential reliability risk.

Although BPA's customers typically take delivery of power directly from a BPA substation or over BPA transmission lines, BPA has indicated that it could deliver power to the City's electric system over PSE's transmission lines. This approach is used elsewhere in the Pacific Northwest where a direct connection to BPA's system is not currently available. BPA would negotiate with PSE for the use of PSE's transmission system to deliver power to the City system and would compensate PSE for this service. An advantage of this approach is that PSE's transmission system would continue to be used in the manner it is now and PSE would receive payments for the use of the system. PSE would, however, continue to be responsible for the maintenance and operation of its transmission system and provide outage restoration. A Line and Load Interconnection

Request[11] will need to be made to BPA to obtain more specific information about the capability of BPA's and PSE's transmission systems to serve the City system and define the specific interconnection equipment needed.

For the purpose of this analysis, we have assumed that the new City electric utility would not acquire the transmission lines north of the Port Madison substation. A metering system would be installed at the Port Madison substation and this is where the new utility would take delivery of power from BPA. From this point the new electric utility would own the substations, the radial transmission lines between the substations, all overhead and underground distribution lines, distribution transformers, customer services, and meters.

Based on our observations and information provided to the City by PSE, we have estimated the quantities and approximate sizes of electric facilities to be acquired by the new utility. Using this information and our experience with electric utility construction and costs, we have estimated a range of costs for the acquired facilities.

Estimated Cost of Electric Facilities

An appraisal of the value of electric facilities to be acquired by the City for its electric system has not been conducted. Such an appraisal would rely upon a detailed description of the facilities to be acquired and will potentially be needed if the City proceeds towards acquisition of the PSE system on Bainbridge Island. Such information could be provided by PSE or it could be developed independently by the City as part of a condemnation legal proceeding.

We have estimated that approximately 7.5 miles of 115-kV transmission lines currently owned by PSE would be acquired by the City. There are three substations and approximately 307 miles of distribution lines of which 165 miles are underground. Since we do not have asset records from PSE or know what the original cost of these specific facilities was, we have estimated the original cost based on estimated current transmission and distribution costs deflated to the cost at the assumed average installation date.

For the purpose of this analysis, the cost the City would pay for the acquired facilities is estimated to be between the original cost less depreciation (OCLD) value and the reproduction cost new less depreciation (RCNLD) value of the electric facilities. OCLD is defined as the original cost of the property when it was first put into service as a public utility, less accrued depreciation. The OCLD value is an estimate of the net book value of property, which in general, is approximately the rate base value of the property for ratemaking purposes.

For state utility commission regulated properties such as the facilities to be acquired by the City, the rate base value generally is the portion of the original investment cost which the utility has not yet recovered through rate charges paid by its customers.

[11] https://www.bpa.gov/transmission/Doing%20Business/Interconnection/Pages/LLIP.aspx

The following table summarizes the estimated RCN, RCNLD and OCLD costs for the facilities expected to be needed by the new City electric system. As previously indicated, the facilities to be acquired do not include the transmission lines north of the Port Madison substation.

TABLE 2
Estimated Costs of Facilities to be Acquired by the City Electric System
($000)

	Assumed Average Install Year	Average Service Life (Years)	Percent Depreciated	Estimated Reproduction Cost New ($000)	Estimated Reproduction Cost Less Depreciation ($000)	Estimated Original Cost Less Depreciation ($000)
Substations and getaways	1994	50	43%	$ 9,800	$ 5,700	$ 2,700
Transmission Lines	1996	50	40%	2,100	1,300	800
Distribution Lines, Services, etc.	2004	50	42%	71,390	41,730	19,190
Total				$ 83,290	$ 48,730	$ 22,690

As indicated in the table, the estimated cost of the facilities based on OCLD and RCNLD ranges between $22.7 million and $48.7 million. If in addition, the City electric system were to acquire the transmission lines north of the Port Madison substation, including the Agate Pass crossing, the estimated cost of the facilities would range between $27.6 million (OCLD) and $54.1 million (RCNLD).

For the purpose of comparison, the estimated total investment in electric distribution facilities on a per customer basis in PSE's total system has been evaluated. This distribution value includes PSE substation facilities, overhead and underground distribution lines, customer connections, meters and other facilities. PSE's total electric plant in service as of December 31, 2015 was $8.9 billion. The investment in distribution plant was $3.4 billion or $3,130 per customer based on the total number of electric customers in PSE's system of 1,103,600. These electric plant and distribution plant in service amounts are based on the original cost of the plant when it was installed. Overall, the value of PSE's distribution plant was 38% depreciated as of December 31, 2015.

Assuming that PSE's investment in Bainbridge Island on a per customer basis is proportional to investment in these facilities throughout PSE's entire system, the total estimated amount for distribution plant in Bainbridge Island would be $38.2 million. Applying 38% depreciation would result in the original cost less depreciation value of distribution plant being $23.7 million. This is comparable to, although slightly higher than the total amount shown for the original cost less depreciation in Table 1. Using PSE's reported average depreciation on distribution plant to estimate the average installation date of distribution plant, the reproduction cost new less depreciation of distribution plant on Bainbridge Island is estimated to be $49.1 million. The value of transmission plant to be acquired would need to be included in the total cost based on this methodology to provide a totally comparable estimated value.

As another point of information, the Washington State Department of Revenue (DOR) has estimated that the equalized taxing value of PSE real and personal property within Kitsap County, adjusted for market conditions in 2016 was $198,096,993[12]. It is important to note that DOR performs a complex review of various assets and information provided to it and then makes adjustments to price the real and personal property at approximately a market value. It is also important to understand that this DOR value includes buildings, transmission lines, substations, distribution facilities, land rights, computer software, etc. The Kitsap County Assessor's Office reports that the DOR assessed value of PSE's real and personal property for property tax purposes for 2017 in the Bainbridge Island tax code areas is $19,593,411.

Stranded Costs

Stranded costs represent a utility's investments in facilities that become unused or redundant as a result of regulatory or market changes. The proposed acquisition concept involves the continued use of portions of PSE's transmission system for which PSE will be compensated and as a result there should not be any stranded costs related to these facilities. The Federal Energy Regulatory Commission (FERC) established the concept of stranded costs after it established a transmission open access policy that requires utilities, such as PSE to provide transmission access. The application of stranded costs is based on a complex set of FERC definitions and formulae that can likely only be resolved by litigation or negotiation. Further evaluation may be needed but it is not expected that stranded costs would have a significant impact on the costs of acquisition for a new utility on Bainbridge Island.

Separation Costs

The physical separation of the electric systems of the new electric utility and PSE is expected to be relatively simple if the new utility takes delivery of BPA power over PSE's transmission system at the Port Madison substation. The new utility will need to install BPA bulk power metering equipment and assure that appropriate protection and switching systems are installed at the substation. The new utility will be responsible for any costs that are incurred to provide separation of the systems.

In the past it has been noted that third party owned customer metering equipment may be installed in PSE's system. If these meters are in the City's system it may mean that there would be some additional costs associated with meter acquisition. In addition, PSE's investment in residential and commercial energy efficiency systems in Bainbridge Island, identified by PSE as $2.8 million, may or may not need to be refunded at the time of acquisition or reflected in the acquisition cost. Likewise, there may be customer service or accounting costs associated with separating the customers from PSE's system and costs of transferring legal assets that may or may not need to be reflected in the acquisition cost.

[12] http://www.dor.wa.gov/docs/reports/2016/utilvals2016/2016_Table_2.pdf

Section 4
Estimated Initial Financing Requirements

Financing Options and Conditions

The costs of acquiring the direct necessary electric facilities are combined with estimates of any necessary new construction costs, legal and consulting fees, engineering costs and startup costs to determine the initial financing requirement for the new utility. Funds are typically borrowed to pay these costs and the borrowed monies are repaid over a fairly long period such as 25 to 30 years. Because of the amount of investment needed to construct electric utility facilities as well as the long useful life of these facilities, electric utilities often have a fair amount of long-term debt to service. It is assumed that the City would finance the initial acquisition costs of the facilities with the issuance of revenue bonds that would not be tax-exempt. Costs of constructing new facilities or facilities for separation, purchases of equipment, inventories, supplies, reserves and other related costs are assumed to be financed with loans carrying tax-exempt interest rates. Certain costs associated with the issuance of revenue bonds, such as the funding of a bond reserve fund, would also be incurred and are included in the estimate of total financing requirements.

Municipally-owned electric utilities and PUD's generally use tax-exempt revenue bonds and loans to fund the capital costs associated with their systems. Federal tax laws generally prohibit the use of tax-exempt loans for the funding of municipal acquisition of electric systems owned by investor-owned or privately owned utilities. Taxable revenue bonds have a higher interest rate than tax-exempt interest rates. For our analysis we have assumed a 4.5% tax-exempt electric revenue bond interest rate and a 5.0% taxable electric revenue bond rate. Further, the 30-year flat repayment schedule for the initial bond issuance, as assumed for this analysis, could be shortened if desired or a non-levelized debt service payment schedule could be established.

A shorter repayment period would require higher annual debt service payments during the repayment period but would allow for earlier retirement of the bonds. It is important that legal and financial advisors be consulted with regard to the structuring of bond issues to fully evaluate financing alternatives. Full principal repayment could be partially deferred in the first year of electric system operation to lower the revenue requirements in the first year. Various exceptions and special conditions could exist that would allow more access to tax-exempt securities to fund the initial financing requirement.

It is important to note that the debt incurred by the new City electric system would be expected to be secured by the revenue of the electric system and not the City's general fund. As such, property taxes and other taxes within the City would not be used to support the electric system bonds.

Requirements for a New Utility to Issue Long-term Revenue Bonds

Issuing long-term debt is fairly common for municipalities, counties and other governmental agencies. A new, municipal electric utility would need to consider some of the following requirements in undertaking a revenue bond financing.

1. Agreement to purchase the system is complete so there is no question about ownership.
2. The governing body is in place (i.e. City Council)
3. A feasibility study has been completed showing projected revenues and expenses.
4. An initial rate schedule based on feasibility study has been adopted by the governing body.
5. Management and staff in place (contracted for or hired) so it is clear that the entity has the capability to run an electric utility.
6. A bond ordinance has been adopted with typical revenue bond covenants including a pledge to raise revenues as necessary to pay debt service, provide adequate debt service coverage, establish an adequate reserve account and address other covenants.
7. Indicate adequate cash on hand to fund startup and initial costs until revenues from rates and charges are received.
8. Have an agreement in place for power supply with BPA and/or other entities.

Additional items would potentially be added as the municipality's legal and financial advisors review the potential structure of the proposed borrowing. If necessary, the municipal entity could possibly issue debt and place proceeds into an escrow account until certain of the above requirements are met. Also, for initial startup costs, the municipal entity could provide funds through a general obligation bond or note or through interfund borrowing. These funds could be used until long term financing is in place and the system is in operation.

Typical Bond Covenants

Typical covenants included in the bond ordinance related to the issuance of municipal utility revenue bonds are shown in the following paragraphs. Bond council and the City's legal council will determine which of these covenants are needed and will adjust the wording as appropriate.

1. *Rate Covenant – General*. Rates will be established, maintained and revenues collected for electric energy sold through the ownership or operation of the electric distribution system, and all other commodities, services and facilities sold, furnished or supplied by the electric system in connection with the ownership or operation of the electric distribution system that shall be fair and nondiscriminatory and adequate to provide gross revenue sufficient for the payment of the principal of and interest on all outstanding Parity Bonds, for all payments which the electric system is obligated to set aside in the bond account, and for the proper operation and maintenance of the electric distribution system, and all necessary repairs, replacements and renewals thereof,

the working capital necessary for the operation thereof, and for the payment of all amounts that the electric system may now or hereafter become obligated to pay from the gross revenue.

2. *Rate Covenant – Coverage Requirement*. Such rates or charges shall be sufficient to provide net revenue in any fiscal year in an amount equal to at least 1.25 times the annual debt service in such fiscal year on all outstanding bonds. A higher coverage requirement can possibly improve the rating of bonds and contribute towards a lower interest rate.

3. *Maintenance of the Electric Distribution System*. The electric distribution system will be maintained in good repair, working order and condition, and all necessary and proper repairs, renewals, replacements, extensions and betterments thereto will be properly and advantageously conducted, and the City will at all times operate such properties and the business in connection therewith in an efficient manner and at reasonable cost.

4. *Sale or Disposition of the Electric Distribution System*. The City will not sell, mortgage, lease or otherwise dispose of or encumber all or any portion of the electric distribution system properties, or permit the sale, mortgage, lease or other disposition thereof, except under certain conditions.

5. *Insurance*. The City will keep the works, plants, properties and facilities comprising the electric distribution system insured, and will carry such other insurance, with responsible insurers, with policies payable to the City, against risks, accidents or casualties, at least to the extent that insurance is usually carried by municipal corporations operating like properties.

6. *Books and Accounts*. The City shall keep proper books of account in accordance with the rules and regulations prescribed by the Washington State Auditor's Office, or other State department or agency succeeding to such duties of the Washington State Auditor's office. In the case of an RUS loan, the books and accounts along with periodic reports shall conform to RUS borrowing requirements (see below).

7. *No Free Service*. Except as permitted or required by law, the City will not furnish or supply or permit the furnishing or supplying of electric energy in connection with the operation of the electric distribution system, free of charge to any person, firm or corporation, public or private, so long as any bonds are outstanding and unpaid; provided, that, to the extent permitted by law, the City may lend money and may provide commodities, services or facilities free of charge or at a reduced charge in connection with a plan of conservation of electric energy adopted by the City Council or to aid the poor, infirm or elderly.

Other Financing Options

The federal Rural Utilities Service (RUS) within the United States Department of Agriculture administers water and waste treatment, electric and telecommunications infrastructure to rural communities. The RUS Electric Program provides capital and leadership to maintain, expand, upgrade and modernize rural electric infrastructure. The loans and loan guarantees provided by RUS finance the construction or improvement of electric distribution, transmission and generation facilities in rural areas. The RUS Electric Program also provides funding to support demand-side management, energy efficiency and conservation programs, and on-and off-grid renewable energy systems.

RUS loans are made to cooperatives, corporations, states, territories, subdivisions, municipalities, utility districts and non-profit organizations. Jefferson County PUD obtained a loan from RUS to finance the acquisition of electric facilities to undertake electric service in Jefferson County beginning in 2013. RUS, in discussions with DHA, has indicated that the City could potentially qualify for an RUS loan to purchase electric facilities, however, an official determination would need to be obtained when more information is available and discussions are conducted with RUS.

RUS loans have an interest rate tied to the treasury rate plus 1/8 point and can typically have a repayment period up to 30-35 years. As of early January 2017, the RUS rate for long-term loans with a 30 year maturity to qualified electric utility borrowers is indicated to be approximately 2.875%.[13] RUS does not assess any fees to establish loans.

Estimated Initial Financing Requirements

It is expected that funds will be borrowed by the new electric utility very close to the beginning of initial utility operation. This initial borrowing will provide sufficient funds to pay initial acquisition costs, construct any new electric facilities needed to begin electric service, pay legal and engineering costs incurred in the development of the new utility, and purchase equipment and materials to begin utility operation. In addition, the initial financing will need to fund the costs of the financing, as well as, establish a debt service reserve fund and any other reserve funds that may be needed to begin utility operation.

Prior to the initial financing, the City will most likely incur costs related to the establishment of the new utility. These costs can include legal, engineering and consulting fees that evaluate the feasibility of the new utility and plan its development. These costs could potentially be paid initially by the City from general funds, for example, and then can be refunded to the City with the proceeds of the initial long-term borrowing. Short-term borrowings could also be used to fund

[13] FFB quarterly rates for 30-year maturity plus 0.125%. https://www.rd.usda.gov/programs-services/services/rural-utilities-loan-interest-rates

some of the early costs. These borrowings would typically be refunded with the proceeds of a long-term borrowing.

For the purpose of this analysis, the estimated initial financing requirement is based on the assumption that the cost to acquire the electric facilities from PSE is two times the estimated original cost less depreciation (OCLD) value of the facilities as shown in Table 2. Other costs we have included in the initial financing requirement are the costs of installing equipment to meter wholesale power purchases at the substations, purchase necessary vehicles and equipment, purchase materials and supplies and pay the costs of additional warehouse and maintenance facilities that the City may need for the electric utility. Note that the acquisition cost is expected to be either a negotiated or court mandated value. We have used 2 times OCLD as an initial estimate of the acquisition cost and included sensitivity analysis to indicate feasible ranges within which an acquisition price might be negotiated.

It is expected that the City would evaluate financing options and undertake loans that provide the most effective and lowest-cost approach. Interest and principal payments on loan balances are included among the costs to be recovered through electric rates so it is important to keep these costs at a reasonable level. Although there are potentially other options, the base case of our analysis assumes that the City would fund the initial financing requirement with a combination of taxable and tax-exempt interest rate revenue bonds. The taxable interest rate bonds would be used to pay PSE for the electric facilities to be purchased. All other costs could be funded with tax-exempt interest rate bonds.

In addition to the loan amounts needed to pay the initial costs of acquisition, startup and improvements, there will also be the need to fund initial working capital and reserve funds. The City may have other options available to provide these amounts. Revenue bonds usually require that a debt service reserve fund equal to one year's debt service be established and maintained as long as any of the bonds are outstanding. A portion of the proceeds of the bond issue are used to fund the debt service reserve fund. The costs to issue bonds are also funded with the proceeds of the bond issue.

Basic assumptions related to the debt to fund the initial financing requirement are as follows:

- Taxable debt interest rate 5.0%
- Tax-exempt debt interest rate 4.5%
- Repayment period 30 years
- Financing expense 1.5% of bond amount
- Debt service reserve One year's level debt service

The estimated initial financing requirements for the new utility are summarized in Table 3:

TABLE 3
City of Bainbridge Island Electric System
Estimated Initial Costs and Total Financing Requirements
(Based on Acquisition at Two Times OCLD Cost)

	Loan A (Taxable Rate)	Loan B (Tax-exempt Rate)	Total
Initial Acquistion Costs	$ 45,380,000	$ -	$ 45,380,000
Separation, Startup, Legal Costs [1]	-	$ 5,220,000	$ 5,220,000
Working Capital [2]	-	2,500,000	2,500,000
Contingency Reserve	-	-	-
Subtotal	$ 45,380,000	$ 7,720,000	$ 53,100,000
Financing Expense [3]	740,000	125,000	865,000
Debt Service Reserve [4]	3,209,000	513,000	3,722,000
Total Financing Requirement	$ 49,329,000	$ 8,358,000	$ 57,687,000

[1] Includes estimated costs of vehicles, equipment, materials, warehousing modifications and legal, engineering and consulting fees.

[2] Assumed to be approximately two months of estimated electric utility operating expenses.

[3] Estimated at 1.5% of loan amount.

[4] Estimated at one year's debt service. Assumes level debt service, 5.0% taxable and 4.5% tax-exempt interest rates and a 30 year repayment period.

Section 5

Estimated Number of Customers and Load Forecast

Electric utilities generally classify their customers based on general characteristics of service. Typical customer classifications are residential (regular, low-income), commercial, industrial, irrigation, governmental, sale for resale and streetlights. The number of customers in the City's service territory has been estimated to serve as the basis for estimating energy sales and overall power requirements of the municipal electric system.

PSE has indicated that approximately 12,300 electric customers are presently served on Bainbridge Island. It is not known how many of these customers are residential and how many are commercial accounts, however, based on the estimated number of residential housing units in the City identified in the 2010 census, we have estimated the number of residential accounts served in 2010 to be approximately 10,700. PSE indicates that the total number of electric customers served on Bainbridge Island has increased about 0.7% on average per year between 2010 and 2016. Applying this average increase factor to the 2010 estimate, the total number of residential customers is estimated to be 11,210 in 2016. Based on this number of residential accounts, there would be an estimated 1,100 commercial and other electric customers in the City in 2016.

Electric energy sales to the residents and businesses in the City have been estimated based on the average energy use per customer in PSE's system in 2015. On average, PSE's residential customers used 10,470 kilowatt-hours (kWh) during 2015 and small commercial customers averaged 28,300 kWh of electric energy use. There is a large variation in the use of power by large commercial customers, however, for the purpose of this analysis it is assumed that large commercial customers in the City have similar average consumption to PSE's average for this class in 2015.

Over time the energy consumption of electric consumers in the City will be expected to change due to a number of factors including changes in weather conditions, energy use patterns, the cost of electricity, the cost of other energy sources, building codes, appliance standards, and implementation of conservation programs, among others. The number of electric customers served is also expected to change most typically with changes in population and the number of housing units. For the purpose of this analysis, we have assumed that the number of customers served will increase in the future at the rate of 0.7% per year on average. The average energy consumption per customer is assumed to remain constant. An alternative case with lower load growth has been evaluated in the sensitivity analysis section.

The total electric energy needs of a utility include the amount of energy sold to customers, uses of energy by the utility itself, and energy losses. Examples of "own-use" energy include the power needed for utility buildings and facilities. Energy losses represent the amount of power "lost" between the point of wholesale power delivery to the utility and the customers' retail meters. A certain amount of power is lost in the conductors and transformers throughout the system. It is assumed that total losses for the new electric utility would be 6.5% of the total energy delivered.

In addition to the electric energy required by the customers in the City, measured in kWh or megawatt-hours (MWh), the maximum demand during the year is also important. Electric demand is metered in kilowatts (kW) or megawatts (MW) and is typically measured monthly for the utility as a whole. For most electric utilities in the Pacific Northwest, the maximum demand occurs during periods of cold temperatures in the winter and during high temperatures in the summer. Another measure of a utility's total load is average MW, the total energy use in megawatt-hours (MWh) divided by the number of hours in the period. In estimating the peak demand, the ratio between average and peak demand, known as the annual loadfactor, has been assumed to be 60%.

The following table shows the estimated number of electric customers, annual energy sales, annual energy requirements and peak demand for the City system for each year, 2016 through 2020.

TABLE 4
City of Bainbridge Island Electric System
Estimated Number of Customers, Annual Energy Sales, Energy Requirements and Peak Demand

	2016	2017	2018	2019	2020
Number of Customers					
Assumed Growth Factor		0.70%	0.70%	0.70%	0.70%
Residential	11,210	11,288	11,367	11,447	11,527
Commercial	1,084	1,092	1,100	1,108	1,116
Other	15	15	15	15	15
Total Customers	12,309	12,395	12,482	12,570	12,658
Energy Sales (MWh)					
Residential	117,400	118,200	119,000	119,900	120,700
Commercial	75,000	75,600	76,100	76,700	77,200
Other	200	200	200	200	200
Total Energy Sales	192,600	194,000	195,300	196,800	198,100
Losses and Own Use	13,400	13,500	13,600	13,700	13,800
Total Energy Reqs. (MWh)	206,000	207,500	208,900	210,500	211,900
Loss % of Total Reqs.	6.5%	6.5%	6.5%	6.5%	6.5%
Total Energy Req. (AveMW)	23.5	23.7	23.8	24.0	24.2
Annual Loadfactor	60%	60%	60%	60%	60%
Peak Demand (MW)	39.0	39.0	40.0	40.0	40.0

As shown in the table, the total annual energy requirement of the City electric system is estimated to be 206,000 MWh, or 23.5 average MW, at present levels. The peak demand is estimated to be 39 MW.

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Section 6
Projected Costs of Operation and Revenue Requirements

Annual Revenue Requirement

Publicly-owned electric utilities generally establish rates to recover revenues through the sale of power sufficient to pay all operating expenses, taxes, and debt service as well as provide a margin from which to fund renewals, replacements and additions to the system. The total of all these cost obligations on an annual basis are referred to as the annual revenue requirement. Operating expenses of the electric system will include purchased power, purchased transmission services, transmission and distribution system operations and maintenance (O&M), customer accounting, and administrative and general expenses.

It is expected that the City will initially either contract for O&M services and/or hire its own staff to perform some or all of these functions. The management and administration of the City's electric system would be expected to be coordinated in some manner with other City operations. The electric utility, however, would need to retain certain specialized management, supervisory and administrative personnel familiar with electric utility operation. If the City were to proceed towards establishing an electric utility a more detailed evaluation of staffing requirements would need to be conducted

At the time of initial operation it would most likely be necessary to contract at least some of the O&M services to other utilities or regional electrical contractors used by other public power utilities and by investor owned utilities. In the past, when new publicly-owned utilities have acquired electric facilities from an existing utility, some of the employees of the acquired utility have been hired by the new utility. This provides both continued local employment for the workers and provides the new utility with necessary skilled workers familiar with the local electric system. Jefferson County PUD contracted with PSE to provide certain O&M services for a period of time when the PUD first became operational. This is another option.

The largest component of cost that the City's electric system would incur each year is the cost of purchased power. This is typical of most electric utilities. Another significant annual expense to be incurred is the interest and principal payments on revenue bonds and other debt obligations. For a new electric utility, annual debt service payments can be relatively large early on but would be expected to become a smaller component of the overall revenue requirements as time goes on. Upon repayment of the initial bonds and loans, the rates of the electric utility could potentially be reduced.

Over time, the electric facilities in the system will need to be repaired, refurbished, and potentially replaced. There may also be the need to expand and improve the system. The costs associated with these efforts will need to be included in the revenue requirement. Electric facilities are typically long-lived and can be funded with additional debt and amortized over the life of the facilities at tax-exempt interest rates. Most electric utilities fund the costs of renewals, replacements and additions through a combination of annual revenues, draws upon reserve funds and new debt.

Many publicly-owned electric systems also collect additional revenues through their electric rates to make tax payments, franchise fee payments and payments in lieu of taxes to local governmental agencies.

Costs that would comprise the annual revenue requirement for the City's electric system are described more fully in this section. For the purpose of the analysis, various assumptions have been made to provide a basis for estimating the annual revenue requirement. The assumptions are based on the factors as described as well as our experience with electric utility operation. The City will have some flexibility in how it operates the electric system and as such, there could be a fair amount of variation in the costs of the operation.

Power Supply Costs

As previously indicated, the most significant annual operating expense that the City's electric system will incur is the cost of wholesale power. Upon fulfillment of certain criteria primarily related to establishing ownership of its distribution system, the new utility will be entitled to purchase power from BPA as a preference customer. The City electric system can reasonably expect to purchase a significant portion, if not all, of its power supply from BPA at the priority firm power rate, also referred to as the Tier 1 power rate.

In addition to BPA, a number of other opportunities for near-term power supply could be available to the City including power purchases from other utilities, independent generating facilities or power marketers. In the future, it is expected that the City will most likely continue to purchase power from BPA but will also be able to participate jointly with other utilities in new generation facilities, contract to purchase power from other suppliers and/or construct new generating facilities of its own locally including solar, wind, wastewater treatment bio-mass, and other renewable resources. The new City utility can also aggressively pursue energy efficiency measure and/or measures to reduce the City's carbon footprint.

For our initial analysis, we have assumed that the full power requirement of the new utility is supplied with BPA wholesale power.

Estimated Cost of BPA Power and Transmission

BPA has provided an estimate of the cost of power and transmission for an electric system with power requirements similar in size to those estimated for the City electric system. The estimated cost of power is based on BPA's rates currently in effect and assumes that the City system would obtain Tier 1 power to meet its total power needs in the first year of system operation. Tier 2 rates are presently about the same as Tier 1 rates so if initially the City system needed to phase in its purchase of Tier 1 power, the cost impact would be minimal.

As a BPA customer, the new utility would pay BPA's Network Integration Transmission Service charge. This charge provides for the delivery of power from BPA's generating resources to the City's delivery point. BPA has indicated that if the City electric system takes delivery of power at transmission voltage and owns the equipment to step the power down to distribution voltage, there would be no GTA delivery charges assessed. The GTA delivery charge only applies if power is delivered to a utility at less than 34.5-kV. If the City system owns the substations on Bainbridge Island, as described previously, the delivery of BPA power would be at a 115 kV transmission voltage, thus avoiding any GTA delivery charges.

BPA has established a policy of reviewing and adjusting its wholesale power rates every two years. The rates are established for a two year period based on BPA's fiscal year which begins October 1. The present rates (BP-16) went into effect on October 1, 2015 and will remain effective through September 30, 2017. The total Tier 1 charge for each BPA customer varies based on each utility's load characteristics, however, the average Tier 1 power rate currently charged to BPA's public power customers is $33.75 per MWh[14].

BPA's power and transmission rates are to be adjusted on October 1, 2017. The BP-18 rate proceeding began in the fall of 2016 and will continue until final rates are approved in the late summer of 2017. The initial proposal provided by BPA for the BP-18 rates indicates an approximately 2.3% increase in overall power charges with the new rates, as estimated by BPA. The initial BP-18 proposal for transmission rates shows little change in the network transmission rate. The BP-18 rates will be effective from October 1, 2018 to September 30, 2019.

It is expected that BPA will continue to adjust its rates every two years in the future. For the purpose of this analysis, it is assumed that Tier 1 rates will increase 6% every two years. BPA Tier 2 rates are assumed to be 15% above the Tier 1 rates. BPA Network Transmission rates are assumed to increase at 6% every two years as well.

Annual Operating Costs other than Power and Transmission

In addition to power supply costs which represent the largest cost component for most electric utilities, the City electric system will incur costs for on-going operation and maintenance of the system, planning, engineering, administration, management, customer service, billing, accounting, and other costs. To provide these electric utility service functions it is expected that the City will hire necessary employees and/or contract out for others. Some of the functions, primarily related to billing, administration and management can be coordinated with current City functions, which may result in some reduced or shared costs by various functions. Certain operation and management functions can be contracted out similar in manner as to how PSE contracts for a significant portion of its maintenance and engineering work.

[14] https://www.bpa.gov/Finance/RateInformation/Pages/Current-Power-Rates.aspx

Among other Northwest public power electric utilities, the number of employees varies significantly. A good example of a municipal electric utility serving a similar number of customers to that of the City electric system is Centralia City Light. Centralia has 30 full time electric employees and approximately 11,500 customers. The City of Port Angeles has 35 electric employees with approximately 9,000 customers, and the City of Ellensburg indicates that it has 14 electric employees with approximately 9,600 customers, although this number does not include billing and accounting personnel.

As another point of reference, in 2015 the PUDs in Washington indicated that the average number of customers per electric employee was 272. Based on the PUD average number, with 12,300 customers, the City system would require about 45 employees. The City service area is far more compact than the service area of the PUDs in Washington, which would indicate a need for fewer employees.

Based on a review of similarly sized municipal electric utilities in the Northwest, we would estimate that the City electric system would need approximately 30-40 employees, but this could vary based on what services the City would contract out and how the electric utility might be integrated with other City operations. Considering all factors, DHA feels that the number of full-time employees (FTE) by function are conceptually identified as follows:

TABLE 5
City Electric System

Example Electric System Staffing (FTE)

Management and Administrative	4
Operations, Maintenance and Engineering	18
Customer Accounting, Customer Service,Conservation	10
	32

The estimated costs of operation for the City electric system will include personnel costs as well as contracted services, materials, supplies, equipment and other expenses. Tree trimming activities will most likely be conducted by a combination of contractors and employees with contractors doing the majority of the work. This will be an important activity for the City system. Meter reading and billing could also be contracted out if the City decided to do so, but should in the long run be incorporated with other City meter reading and billing functions. It could also be possible to contract out the majority of operations and maintenance to another utility or to an independent contractor. A subset of certain engineering and system planning efforts are expected to be contracted out in the early years of operation and used as a method of providing staff training.

A significant advantage for the City with its own electric utility staff would be some regular permanent presence of utility workers, equipment and materials in the City. Line and service crew workers can be available to conduct maintenance and storm restoration functions relatively quickly. It may still be necessary to use contract workers for certain major activities. The regular presence of utility workers can have a noticeable impact on monitoring of vegetation management issues and in working within the community to assure proper care of trees and manage vegetation growth around power lines. As an example, some utilities provide landscape gift certificates to home owners to help pay for the cost of low growing plants to replace larger plants that pose significant risk to power lines.

For the purpose of developing an estimate for the operating costs of the new electric system, we have reviewed the costs of electric operations for a number of PUDs in Washington. Acknowledging the size and characteristics of these utilities, we have estimated unit costs based on the number of customers served or the amount of electric energy sold and applied the unit costs to the City electric system. These costs are inclusive of labor, benefits, contracted services, materials and other expenses.

Projected Revenue Requirements

The annual revenue requirements have been projected for the first ten years of City electric system operation. Electric system operation is assumed to begin in 2020. Unit operating costs, other than power and transmission costs, are assumed to escalate at 2% per year.

The cost of BPA power to the City system at current BP-16 rates, as estimated by BPA, is $36.50 per MWh. BPA power costs are assumed to increase 2.3% in 2018 [15] and are assumed to increase 6% every two years thereafter. BPA transmission rates are assumed to increase 2.0% in 2018 and are assumed to increase 6% every two years thereafter. The cost of BPA network transmission to the City system, as estimated by BPA, is approximately $4.75 per MWh at current rates.

Annual debt service payments are based on level debt repayment of bonds issued to finance initial acquisition and startup costs (see Table 3) at assumed annual interest rates of 5.0% for taxable debt and 4.5% for tax-exempt debt over a 30 year repayment period. These interest rates are higher than interest rates that the City would potentially incur at the present time. Future economic conditions will impact what the interest rates will be at the time of actual issuance of tax exempt and taxable bonds.

The City electric system will be expected to incur annual expenses for renewals, replacements and additions to the system, assumed to be approximately 3.5% of the system replacement value per year. Annual expenditures for capital replacements and additions are projected to be funded out

[15] BPA's rates are adjusted at the beginning of BPA's fiscal year, October 1. The next rate adjustment will be October 1, 2017. For this analysis, it is assumed that the full impact of the BPA rate adjustments occur in the calendar year following the rate adjustment.

of annual revenues. If the amounts estimated for capital replacement are not used in any given year, they can be retained in a reserve fund for use in the future. In developing the estimated annual revenue requirement, the state utility tax of 3.873% has been included. It is presumed that the City would continue to require a municipal tax, currently 6.0%, on electric bills and this tax could be included in the overall revenue requirement or it could be included as a separate line item on customer bills. The municipal tax is not included in the revenue requirement in this analysis. The projected annual revenue requirements for the City electric system, assuming startup in 2020 are shown in the following table:

TABLE 6
City of Bainbridge Island Electric System
Projected Annual Revenue Requirements
(Base Case)
($000)

	2020	2021	2022	2023	2024	2029
Operating Expenses						
Purchased Power [1]	8,390	8,450	9,030	9,100	9,720	11,340
Network Transmission [2]	1,080	1,110	1,180	1,180	1,250	1,370
Trans. Oper. & Maint. [3]	130	140	140	140	150	170
Dist. Oper. & Maint. [3]	2,890	2,960	3,050	3,130	3,210	3,670
Customer Accounts [3]	990	1,020	1,050	1,080	1,110	1,260
Admin. & General [3]	1,110	1,140	1,170	1,200	1,240	1,410
Taxes [4]	870	880	920	930	970	1,080
Total Operating Exp.	$ 15,460	$ 15,700	$ 16,540	$ 16,760	$ 17,650	$ 20,300
Debt Service						
Initial Loans [5]	$ 3,720	$ 3,720	$ 3,720	$ 3,720	$ 3,720	$ 3,720
Subsequent Loans [6]	-	-	-	-	-	-
Total Debt Service	$ 3,720	$ 3,720	$ 3,720	$ 3,720	$ 3,720	$ 3,720
Renewals, Replacements & Additions						
Funded from Revenues [7]	$ 3,350	$ 3,420	$ 3,490	$ 3,560	$ 3,630	$ 4,010
Funded from Debt	-	-	-	-	-	-
Total Ren., Repl, Adds.	$ 3,350	$ 3,420	$ 3,490	$ 3,560	$ 3,630	$ 4,010
Less: Interest Earnings [8]	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)	$ (60)
Total Sales Rev. Required [9]	$ 22,470	$ 22,780	$ 23,690	$ 23,980	$ 24,940	$ 27,970
Total Energy Sales (MWh) [10]	198,100	199,500	200,900	202,300	203,700	210,900
Unit Revenue Req. (¢/kWh) [11]	11.3	11.4	11.8	11.9	12.2	13.3
Debt Service Coverage[12]	1.88	1.90	1.92	1.94	1.96	2.06

[1] Estimated cost of BPA power purchases.
[2] Estimated cost of BPA network transmission services.
[3] Assumed to increase annually relative to changes in sales and customers and includes inflation at the assumed rate of 2.0%.
[4] Includes state utility tax of 3.873%.
[5] Interest and principal on initial acquisition bond issues shown in Table 3. Assumes level debt service, 5.0% taxable and 4.5% tax-exempt interest rates and a 30 year repayment period.
[6] No additional debt is assumed to be incurred during the analysis period.

[7] Estimated annual cost of renewals, replacements and additions to the electric system facilities. Cost is assumed to be funded from revenues each year.

[8] Estimated interest earnings on invested reserve fund balances at a 1.5% interest earnings rate.

[9] Sum of Total Operating Expenses, Debt Service, and Total Renewals, Replacements and Additions, less interest earnings.

[10] Estimated energy sales assuming 0.7% annual load growth.

[11] Total Revenue Required divided by Total Energy Sales.

[12] Calculated as Total Sales Revenue Required less Total Operating Expenses divided by Total Debt Service.

Debt service coverage is required by bond underwriters and is typically set at a minimum of 1.25 times annual debt service for publicly-owned distribution electric utilities. Publicly-owned utilities usually establish a policy concerning the percentage of capital improvements to be funded from bonds and the amount to be funded from current revenues. The policy may be driven to some extent by limits on the amount of bonds that financial institutions will reasonably allow particular utilities to incur.

The City's main source of revenue for the electric utility will be through the sale of power to its customers. Table 6 shows the estimated revenue requirements for the period, 2020 through 2029. As can be seen in Table 6, the total unit revenue requirement in the first year (2020) of the projections is estimated to be 11.3 cents per kWh. Note that if the 6.0% municipal tax were included in the revenue requirement, the unit revenue requirement in 2020 is estimated to be 12.1 cents per kWh. The unit revenue requirement, which is the average unit revenue that the City would need to collect through energy sales to its customers, is projected to increase somewhat through the projection period shown in Table 6 due to general inflation in operating costs and expected increases in the cost of wholesale power and transmission services purchased from BPA.

Average revenue requirements are not specific rates. Rates will need to be adopted by the governing board of the City electric system. Rates would need to be established that would reflect the actual cost to serve certain customer classifications (i.e. residential, small commercial, large commercial). The rates could also include multiple components such as monthly basic charges (e.g. $10.00 per month), demand charges and energy charges and or blocks or energy tiers or monthly/seasonal components. The total amount received through these various rate components, however, would need to approximate the estimated Total Sales Revenue Required shown in Table 6 on an annual basis.

Section 7
Estimated Net Benefits and Comparison of Rates

The estimated annual revenue requirements for the City electric system derived in Table 6 are representative of the average weighted rates for electric service that the City system would charge its various customers. Comparing these average charges to PSE's electric system average revenue requirements allows for an evaluation of the net benefits that electric consumers on Bainbridge Island would realize with the City electric system. With a public power utility the benefits are very long-term in that they are realized far into the future. For a new utility with a fairly high initial investment, the full level of benefits may not be realized until the initial loans are repaid. The long-term benefits are potentially many years in the future and as a result, are valued less today. Although an estimation of net benefits in the first ten years of new utility operation are presented in this analysis it is important to acknowledge that benefits would typically be greater in the future.

The estimation of revenue requirements for the new City electric system have been developed based on the assumptions and variables defined in the previous section of this report. PSE's future revenue needs and resulting rates are dependent on many complex factors. Although PSE's current electric rates are published in detail, we are unaware of any detailed projections of future PSE electric rates. As such, to compare the estimated future rates of the City electric system to the future rates for PSE electric service, it is necessary to develop an estimate of PSE's future charges.

A compilation of rate adjustments[16] from the Washington UTC indicates that PSE's charges for electric service were adjusted a number of times between April 2002 and January 2015. Many of the adjustments were minor and were for specific changes in direct costs such as conservation. Over the thirteen year period shown in the rate compilation, it appears that the adjustments to electric rates averaged approximately 2.5% per year[17].

As another comparison, PSE's monthly charge for electric service to residential customers with average power consumption increased at an average rate of about 1.6% per year between January 2009 and October 2016, exclusive of the residential energy exchange credit.

In recent years, PSE's electric rates have remained relatively stable. PSE filed a general rate case on January 13, 2017[18]. In the rate filing PSE indicates that the net impact to customers' rates is anticipated to be an increase in electric rates of 4.1%. The revised tariff sheets provided with the rate filing reflect the issue date of January 13, 2017 and an effective date of February 13, 2017.

PSE's FERC Form No.1 for 2015 indicates that the average unit revenue from its customer classes in 2015 were as follows:

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[16] Source: Electric and Natural Gas Rate Adjustments since 2000. Washington Utilities and Transportation Commission. https://www.utc.wa.gov/regulatedIndustries/utilities/energy/Pages/default.aspx

[17] Without adjustments noted to be associated with the residential exchange credit, which primarily impacts residential rates, the average annual increase is approximately 3.2% over the thirteen year period.

[18] http://www.pse.com/aboutpse/Rates/Documents/prop_2017_01_and_02_2017_GRC_elec_gas.pdf

TABLE 7
PSE Average Unit Revenue in 2015 for Representative Customer Classes
(Compiled from PSE 2015 FERC Form No. 1)

	2015 Revenue (¢/kWh)
Residential [1]	10.44
Small Commercial [2]	9.64
Industrial [3]	9.08
Street and Highway Lights	22.82
Total for all Sales	10.06

[1] Includes combined Residential Service customer classes.

[2] Includes Farm General Service and Commercial Schedules 24, 25, 26, 49 and other commercial tariffs.

[3] Combined industrial revenues

The WUTC requires the utilities it regulates to develop an integrated resource plan (IRP). In a recent presentation[19] related to its current IRP development process, PSE indicates that its input assumption for average annual electric residential rate growth is 2.1%. Using this value along with the historical adjustments for the purpose of comparing future rates we have assumed that PSE rates will increase 2.3% per year beginning in 2018. PSE rates have been assumed to increase 4.1% in 2017 pursuant to the January 13, 2017 rate filing.

Based on the unit revenues shown in Table 6 with adjustments for current charges and the estimated energy sales in the City electric service area as shown in Table 3, the total cost of electric service to residents and businesses in the City with continued service from PSE has been estimated for a ten year projection period.

The cost of continued electric service with PSE is compared to the cost of electric service from the City electric system assuming the City electric system were to establish rates to recover the estimated revenue requirements as shown in Table 6. The comparison of charges is shown in Table 8 for the ten year period, 2020 through 2029. It is important to note that the average unit revenues shown in Table 8 for PSE are reflective of the estimated sales by customer class in Bainbridge Island.

[19] 2017 IRP Advisory Group presentation, Page 35. November 14, 2016. http://pse.com/aboutpse/EnergySupply/Documents/Post_IRPAG_Nov14_IRPAG_Distribution.pdf

TABLE 8
Comparative Charges for Electric Service and Estimated Savings
With City Electric Service

	2020	2021	2022	2023	2024	2029
Energy Sales (MWh)						
Residential	120,700	121,500	122,400	123,200	124,100	128,500
Commercial	77,200	77,800	78,300	78,900	79,400	82,200
Industrial	-	-	-	-	-	-
Other	200	200	200	200	200	200
Total Energy Sales (MWh)	198,100	199,500	200,900	202,300	203,700	210,900
Estimated PSE Revenues from Energy Sales in City						
Assumed Increase in Rates	2.30%	2.30%	2.30%	2.30%	2.30%	2.30%
Revenues ($000) [1]	$ 23,100	$ 23,700	$ 24,500	$ 25,200	$ 26,000	$ 30,100
Unit Revenues (¢/kWh) [2]	11.66	11.88	12.20	12.46	12.76	14.27
Estimated City Electric System Revenues from Energy Sales						
Revenues ($000) [3]	$ 22,470	$ 22,780	$ 23,690	$ 23,980	$ 24,940	$ 27,970
Unit Revenues (c/kWh) [2]	11.34	11.42	11.79	11.85	12.24	13.26
Savings with City System ($000)	$ 630	$ 920	$ 810	$ 1,220	$ 1,060	$ 2,130
Savings with City System (¢/kWh)	0.32	0.46	0.40	0.60	0.52	1.01
Savings with City System (%) [4]	2.7%	3.9%	3.3%	4.8%	4.1%	7.1%
Cumulative Savings with City Electric Service - First 10 Years ($000)					$ 13,110	
Net Present Value of Savings - First 10 Years ($000) [5]					$ 8,721	

[1] Calculated using average customer class revenue and estimated customer class loads with assumed increase in rates applied uniformly to each customer class.
[2] Revenues divided by Total Energy Sales.
[3] Estimated Total Revenue Required for the City electric system as shown in Table 6.
[4] Relative to estimated PSE revenues.
[5] Cumulative present value to 2017 of estimated savings with City electric service over the first ten years of operation, 2020 through 2029. Assumes a 4.5% discount rate.

As shown in Table 8, the estimated cost of electric service with the City electric system is estimated to be slightly lower than the cost of service from PSE. By 2029, the annual savings are estimated to be about 7.0%. Over the first ten years of operation, electric consumers in the City are estimated to pay approximately $13.1 million less in total with City electric service than they would with continued service from PSE.

Rather than establish rates that would achieve the estimated savings shown in Table 8, the City could establish higher rates and use the savings amount to invest in renewable generation resources, additional energy efficiency programs or improvements to the electric system, such as additional undergrounded power lines.

Alternative assumptions to the analysis would result in different results. Key variables include the estimated cost of acquisition, the estimated cost of financing, and assumed increases in the number of electric customers served and load growth on Bainbridge Island. As previously indicated, the acquisition price will be either negotiated or established in a court proceeding. The base case analysis assumes the acquisition price is 2 times the estimated OCLD of the system facilities. Alternative cases have been developed to evaluate the net costs and benefits with acquisition at 1.35 times OCLD (Case 2) and at the estimated RCNLD value (Case 3).

The cost of financing related to the initial system acquisition will be a significant cost. If the City could obtain a lower interest rate loan through the federal RUS it could realize a lower revenue requirement. An alternative case assuming a 3.0% interest rate loan from the RUS with a 30 year repayment has been developed (Case 4). With an RUS loan there would be no loan origin fees and it is not expected that there would be a debt service reserve fund. This lowers the overall financing requirement. To determine the impact of lower customer and load growth in the City a case with customer growth at 0.35% per year, half the assumed base case growth, has been developed (Case 5).

Table 9 provides a comparison of the estimated net benefits with City electric service using alternative assumptions for certain variables. It should be noted that for each alternative case, only the specifically identified variable is changed. All other assumptions are kept at the base case values. Scenario analysis or sensitivity analysis can help the City identify the most important variables or where the most risk/reward to forming an electric utility resides.

TABLE 9
Comparative Net Benefits with Alternative Assumptions

Case	Basis of Initital Acquisition Cost	On-line Year	Initial Financing Requirement	Interest Rates	First Year Unit Revenue (¢/kWh)	Savings with City System over first 10 Years
1 (Base)	Initial Acquisition at 2 times OCLD	2020	$57,687,000	5.0% taxable, 4.5% tax-exempt	11.3	$13,110,000
2	Initial Acquisition at OCLD + 35%	2020	$42,739,000	5.0% taxable, 4.5% tax-exempt	10.8	$23,000,000
3	Initial Acquisition at RCNLD	2020	$61,329,000	5.0% taxable, 4.5% tax-exempt	11.5	$10,620,000
4	Initial Acquisition at 2 times OCLD, Initial loans financed through RUS	2020	$53,100,000	3.0% on all debt	10.8	$23,000,000
5	Initial Acquisition at 2 times OCLD, Customer growth at 0.35% per year	2020	$57,687,000	5.0% taxable, 4.5% tax-exempt	11.4	$10,170,000

As can be seen in Table 9 the total estimated savings with the City electric system are significantly higher in the lower acquisition cost case (Case 2) and in the lower financing cost case (Case 4) than for the base case. If the acquisition cost is higher (Case 3) the savings are less. Lower load growth (Case 5) also reduces the estimated savings of the City electric system since there are fewer units of sales from which to recover revenues needed to pay the fixed costs of the system.

It should also be noted that if PSE's rates do not change as assumed in this analysis, the estimated savings with the City electric system will be different.

Comparative Electric Rates

A comparison of charges for electric service for several electric utilities primarily in Western Washington has been made. Rates effective on January 1, 2017 were used to determine the cost of monthly service for a residential customer consuming 1,000 kilowatt-hours and a small commercial customer receiving 6,000 kilowatt-hours per month. The monthly charges are shown in the following table:

TABLE 10
Comparative Monthly Charges for Electric Service
(Based on Rates Effective on January 1, 2017)

	Residential (1,000 kWh)	Commercial (15 kW, 6,000 kWh) [1]
Puget Sound Energy	$104.71	$587.15
Public Utility Districts		
Jefferson County PUD	$106.94	$587.43
Mason County PUD No. 3	$105.70	$517.20
Clallam County PUD	$94.05	$436.30
Snohomish County PUD	$98.79	$537.60
Municipalities		
City of Port Angeles	$96.11	$461.41
City of Ellensburg	$82.02	$397.64
Seattle City Light	$107.07	$554.19
Tacoma Power	$84.65	$481.56
Cooperatives		
Orcas Power & Light	$136.44	$660.31
Lakeview Light & Power	$94.00	$529.50

[1] Assumes single phase service. Winter rates used where applicable.

As can be seen in Table 10, there is significant variation in the charges for electric service among the various utilities. It should also be noted that additional local taxes may apply to electric charges.

As previously indicated, actual rates would need to be developed for the City system that would recover the estimated revenue requirement. Rates usually include a monthly customer charge and an energy charge. Larger commercial customers typically have a demand component in their rates related to the largest level of power use during the month. Demand charges require a demand meter.

A comparison of residential electric rates effective on January 1, 2017 for the same group of electric utilities is shown in the following table:

TABLE 11
Residential Rates for Electric Service
(Based on Rates Effective on January 1, 2017)

	Basic Charge ($/month)	Energy Charge (¢/kWh)
Puget Sound Energy[1]	$ 7.87	8.93 first 600 kWh, 10.81 all other kWh
Public Utility Districts		
Jefferson County PUD	$ 14.50	8.50 first 600 kWh, 10.36 all other kWh
Mason County PUD No. 3	$ 33.00	7.27
Clallam County PUD	$ 25.75	6.83
Snohomish County PUD	$ -	9.88
Municipalities		
City of Port Angeles	$ 19.11	7.70
City of Ellensburg	$ 17.26	6.26 first 600 kWh, 6.80 all other kWh
Seattle City Light	$ 4.86	7.01 first 480 kWh, 12.88 all other kWh
Tacoma Power	$ 10.50	7.41
Cooperatives		
Orcas Power & Light	$ 40.54	9.59
Lakeview Light & Power	$ 19.00	7.50

[1] Energy rates include net effect of applicable credits and charges including the energy exchange credit. Rates shown do not include impacts of PSE's general rate filing dated January 13, 2017.

It is noted that there is significant variance in the monthly basic charge. For some utilities, a higher basic charge can be used to recover necessary revenues when many customers are part-time or seasonal residents.

Section 8
Other Factors

High-Speed Broadband

The City could develop and finance its own high-speed broadband network to serve its residents and businesses. See In Re City of Edmonds, 162 Wn. App. 513 (2011) (upholding code city's authority to complete and finance its fiber optic network as part of a city-owned broadband network). The potential benefits include cost efficiencies, community service, economic stimulation, enhancing public safety, and others. As with the City of Edmonds, it is not a requirement that the City have an electric utility to engage in telecommunications.

There can, however, be advantages to having an electric utility system and engaging in telecommunications activities. Thus, for example, where some of the telecommunications activities are related to services needed by the City for its internal purposes, such as automated meter reading, connecting different City facilities with one another, security, etc., some of the telecommunications expenses might appropriately be attributed to the electric or other system. The same generally would be true, perhaps in varying degree, of a separate water or other system, even in the absence of an electric utility system.

Some public entities conduct their telecommunications activities as a separate utility system; others do so as a department or division of other of their utility systems. Further detail on the financial, practical, and political advantages and disadvantages of creating a separate telecommunications utility, versus structuring it as a component of another system, is beyond the scope of this report, but would merit further review if the City so desires.

Energy Efficiency Opportunities

BPA has historically provided a very robust energy efficiency program that touches all the various sectors (residential, commercial, industrial) in an electric utility's service area. If the City were to become a customer of BPA, they would be assigned a BPA Energy Efficiency Representative (EER). The EER would work with the utility to help identify energy efficiency or conservation opportunities on Bainbridge Island. The EER would inform the utility of BPA programs and assist the utility with reporting savings to BPA. BPA's programs are reviewed for cost effectiveness and funded in large part by BPA revenues.

The way the BPA energy efficiency programs work are that each utility is assigned an energy efficiency budget amount for a BPA rate period, which is typically 2 years. Throughout the term, as a utility completes energy efficiency or conservation projects, they report the energy savings to BPA and get reimbursed for the savings achieved. The payment is from their energy efficiency budget and the reimbursement is sent directly to the utility. There is an opportunity for utilities that are aggressive in implementing conservation to make applications to use portions of other utilities unused energy efficiency budgets. There is also a provision where utilities can join together to pool their energy efficiency budgets. There are also opportunities to make presentations to BPA for funding of energy efficiency measures that are not part of the BPA measures, but meet the cost effectiveness criteria.

The current BPA energy efficiency measures can be found in the Implementation Manual on the BPA website: https://www.bpa.gov/EE/Policy/IManual/Pages/default.aspx. The number and complexity of the programs and measures are significant. To a degree, a utility customer of BPA can work with BPA to pick and choose energy efficiency measures that better reflect the needs of its customers. Some PNW consumer owned utilities focus their conservation programs on low income elderly, residential, small commercial and governmental sectors as a way of keeping maximizing societal benefits, and jobs in their service territory.

Historically, BPA programs have focused on weatherization (HVAC, windows, insulation) in the residential sector, lighting in the commercial and municipal sector and variable speed motor programs in the commercial and industrial sectors. BPA residential programs are shifting to LED lighting and energy efficient appliance rebates, as the other efficiency measures have saturated the market. In the commercial section the shift is toward HVAC and web-enabled devices. Future BPA programs are likely to focus even more on web-enabled devices as a way of providing ancillary services and helping with demand management.

PSE also has a large number of energy efficiency programs. These programs can be found on a series of web pages starting with: http://pse.com/savingsandenergycenter/Pages/default.aspx. PSE has historically provided a large number of energy efficiency programs on Bainbridge Island and has attempted to implement demand side management programs to defer the need for an additional substation on the island. In areas where PSE has natural gas service there are some fuel switching programs. PSE energy efficient appliance rebates are similar to those of neighboring public power utilities. PSE also has many LED lighting and HVAC programs as well.

In many respects the City of Bainbridge Island is a leader in many energy efficiency or “green” areas. There are a large number of roof mounted solar panels, a large number of electric vehicles, and a number of Tesla battery power walls being permitted. As such, through local control a City electric utility could provide more focused energy efficiency measures to meet the needs of the City residents and businesses.

For example, even though the Washington State Energy Code is very aggressive, some cities, such as Seattle, have adopted even more aggressive energy codes. The City, could adopt a more stringent energy code than the State. The City could also, if it chose to, aggressively require remodeling permits to bring large parts of a structure or facility up to current energy codes. Likewise, the City could require remodeling permits to include an energy efficiency analysis that identifies cost effective energy efficiency measures that might be warranted. Alternately, the City could encourage through reduced permitting fees with City Council approval, permitting requirements that would encourage more “Net Zero” buildings or LEED certified buildings.

Currently the City does allow developers of plats and large developments to gain density benefits if they implement certain Net Zero or LEED programs.

Net Zero buildings are a comprehensive conceptual design approach developed by the National Renewable Energy Laboratory (NREL) and refer to buildings that have four basic groupings and within the groupings letter grades:

- Net Zero Site Energy, which on an annual basis produces at least as much renewable energy within the site footprint as it consumes.
- Net Zero Source Energy, which produces or purchases at least as much renewable energy as it consumes.
- Net Zero Energy Cost, where the annual amount of money paid to the building owner by the utility for the generation of on-site renewable energy exported to the grid is equal to or more than the cost of the utility energy services purchased.
- Net Zero Emissions, is where a building produces or purchases enough emission-free renewable energy to offset emissions from all energy used in the building annually.

LEED (Leadership in Energy and Environmental Design) is a comprehensive approach to building design certified and regulated through the US Green Building Council. Its focus is on:

- Locations and transportation
- Sustainable sites
- Water efficiency
- Energy and the atmosphere
- Material and resources
- Indoor Environment
- Innovation
- Regional priorities

Each of these factors includes prerequisites and point credits. If all of the prerequisites are met and sufficient points are achieved and demonstrated, then a building or development can become one of four LEED categories:

- Certified
- Silver
- Gold
- Platinum

It is difficult to make a 20 year projection of energy efficiency as codes and the market place are making rapid changes. For example, the amount of electricity used by LED lights and the improvement in this technology is dramatically changing the State of Washington Energy Code. What would have been considered an impossibly low energy use per square foot a few years ago is now part of the current building code that the City Planning Department reviews for compliance with building plans and inspects to. Similarly, Energy Star washing, drying and dishwashing appliances of today are far more energy and water efficient than those of just 5 years ago and are projected to be even more efficient in the future. What we can say is that new buildings will use far less energy than historically designed buildings and that retrofit or remodeled buildings will also use less energy than they use today.

It is noted that one of the reasons indicated to be contributing to lower market power prices being experienced in recent years is lower demand due to energy efficiency programs, new energy efficient lighting, appliances and electrical equipment being used today.

Socially Responsible Initiatives

Many consumer-owned utilities provide discounts to low income residents and seniors. There are many categories of electric utility rate programs for low-income customers. Some of them include the following:

- Flat rate discount or an across the board percentage discount. Similar to the 50% low income senior and low income disabled rate discount provided to the City water and sewer customers
- Payment programs that cover only the variable costs of serving the customer and/or a discount on the fixed costs.
- Percentage if income plans, where the maximum energy bill is set to a percentage of income based on the Federal Poverty Level of household data.
- Waiver of all or a portion of fixed or monthly fees.
- Blocked rate or lowest tier approach. This is where the customer purchases all power at the lowest tier rate even if they exceed the low tier quantity.
- Lifeline rate, based on a minimum quantity of electric power.
- Seasonal discounts, either tied the winter heating season or in other parts of the country the air conditioning season.
- Special discounts, specifically associated with the electrical consumption of certain life sustaining medical equipment or equipment associated with preventing deterioration of a medical condition.
- Direct vendor payment approach. Customers receive a rate discount when they agree to allow utility bill payment to be taken directly out of a public benefit that customer may

receive, such as Aid to Families with Dependent Children or other programs. Similarly, if there were arrangements with a Quest logo organizations, a bank or credit union funds could be transferred from a Washington DSHS EBT Quest Card. The City already has ACH and bank initiated Bill Payer methods of paying utility bills, so such methods or extensions of them could be incorporated into an electric utility.

There are also federal programs to benefit this class of customers, such as the Low Income Home Energy Assistance Program (LIHEAP), which is focused on helping low income households manage and meet their home heating and/or cooling needs. This can include one-time crisis oriented financial assistance, weatherization grants to reduce heating or cooling needs, free energy efficiency upgrades to lower utility bills while improving the health and safety of the household's occupants, energy budget counseling, education on energy efficiency practices, etc. Such kinds of programs can include implementation of solar or other renewables in some jurisdictions.

There are also State and local programs that can be targeted at this customer class. They range from Department of Commerce grants and Weatherization Assistance Program to local programs offered by Kitsap Community Resources or specific charities.

Most consumer owned electric utilities target federal, BPA, state conservation programs and conservation assistance at their low income elderly customers so as to create socially responsible community programs. BPA has a long history of identifying conservation programs that its utility customers can target to improve the lives of low income elderly customers. Also, the State of Washington, through the Department of Commerce has conservation programs that target low income residents of the state. The City as an electric utility could partner with both to deliver such programs locally.

According to the PSE website, PSE has two programs (beyond LIHEAP and local agency programs) to keep bills low and income-eligible customers warm in the winter:

- HELP or Home Energy Lifeline Program provides qualified customers with bill paying assistance beyond that offered by the federal LIHEAP program.

- The PSE Weatherization Assistance Program (aligned with the Washington State Department of Commerce Weatherization Assistance Program) provides for upgrades to home insulation, sealing air leaks, and lighting and refrigeration replacements.

An important advantage of a City electric utility is local control. This is especially true when it comes to Socially Responsible Initiatives. That is, the City will be in better touch with the needs of its residents than almost any other organization and can adjust programs for the unique mix and needs of Island residents. For example, if life sustaining medical equipment is an especially important need within the City, rates and methods of qualifying for such a rate can be implemented similar to those used by the LADWP.

Alternately, there can be multi-utility benefits identified by the City and factored into a socially responsible rates or appliance rebates/grants or programs. For example, for qualifying customers who purchase electricity, water and have wastewater treated by COBI, there could be a recognition that a new energy efficient dishwasher or clothes washing machine will save electric energy, and help avoid Tier 2 BPA power, will reduce the quantity of potable water that needs to be produced, treated and distributed by COBI and further reduces the amount of waste water that needs to be treated and sludge that needs to be disposed of by COBI.

Similarly, City government can in a combined utility way accomplish other kinds of programs not usually implemented if different utilities provide services. An example of this is the City of Anchorage, Alaska. The George M. Sullivan combined cycle power plant owned by Anchorage Municipal Light and Power uses potable City water through an additional heat exchanger to providing cooling for the steam condensers. This was done for a variety of reasons, including enhanced electric utility power generation economics and winter fire protection, and fire hydrant freeze protection. A conservation benefit of this integrated municipal decision was that the potable water to the city residents is slightly warmer than it would be otherwise. This reduces the need for home and commercial water heating by an incremental amount.

Synergies and Other Benefits

Synergies

Many city electric utilities are very efficient. For example small utilities like Sumas and Blaine compete on the basis of electric rates very favorably with PSE. Various synergies are a significant part of the reason for the comparability of rates with a much larger utility.

Local control can reduce the complexity of regulation and the bureaucracy associated with a large organization that is regulated by multiple governing bodies (Security Exchange Commission, Washington Utilities and Transportation Commission, Federal Energy Regulatory Commission, corporate owners, and utility management). By having a City Council or utility board as the primary regulatory body, various reports, studies, and costly legal proceedings are reduced. Considering that WUTC and FERC hearings are often before administrative law judges with specially hired expert witnesses, costs per proceeding can easily reach six figures. Alternately, presentations by City staff to a City Council or utility board are much less costly.

Another form of synergy often found by municipal utilities is in customer billing and invoicing, where water and/or sewer bills and/or meter reading costs can be combined. While the City only serves a portion of the Bainbridge Island with water and sewer service there is still some potential for savings, although not as great as other cities. Many small electric utilities the size of the City would also not require full time human resources staff, attorney, public relations, off hour call answering, or certain other administrative functions. With a City electric utility a portion of an FTE (full time equivalent) could be assigned to the electric utility for such positions and save the remainder of the FTE cost.

Alternately, synergies can arise from coordination on public works projects. Some municipal electric utilities of which we are familiar coordinate road paving projects with sewer line, water main, and electric utility projects, especially undergrounding projects. The main cost in electric utility undergrounding projects are the costs associated with trenching and site restoration at the end of the project. This kind of sharing has the benefit of reducing certain shared expenses among all the utilities.

Another synergy is that certain kinds of policies, such as unmetered services, that result in very expensive connection costs can be avoided. There are a number of situations where cross walk warning lighting, or traffic control equipment may have high connection costs, while the amount of energy used is trivial.

Other Non-Economic Benefits

Sometimes locally controlled utilities better understand their customers and the needs of their community. An example of this is the City of Sumas. At one point the mayor and city council wanted to encourage more jobs locally. During an electric rate proceeding, they directed their consultant to establish industrial rates that did not change the cost allocations between customer classes, but did change the rate form in a way that would reduce the cost impact of adding a second or third shift of operation at a local industry.

In communities such as the City of Blaine and the Town of Steilacoom, the governing board has established resolutions favoring the undergrounding of new electric utility distribution lines. These long term policies have gradually changed both utilities to mostly underground service, which allows them both to have low storm outage rates and better electric reliability than a similar overhead electric utility.

Another example of recognizing a local problem and implementing different local reliability solutions can be learned from Grays Harbor County PUD, Peninsular Power & Light Company, and Ferry County PUD. At Grays Harbor County PUD, they had a localized, but significant high voltage reliability problem where a subtransmission line with distribution underbuild on the same pole was subject to impacts from trees blowing over during wind storms. This resulted in trees contacting both transmission and distribution lines at the same time and having significant high voltage spikes occur within home wiring that destroyed TV's, computers and various electronics. Part of Grays Harbor County PUD's solution was to offer meter socket, whole house, surge protectors to customers in the affected area at cost.

Another similar reliability example was where Peninsula Light Company offered a program of supply auxiliary gas/diesel generators and isolation equipment as a package for customer in remote areas who desired back up power sources. Similarly, Ferry County PUD provided some remote homeowners with non-grid connected solar photovoltaic systems. Again, the idea is that a locally controlled electric utility can identify a community need or the needs of a small set of customers and develop a program to meet those needs.

Another synergy is associated with employees living within the COBI service area and being an important part and source of skills for the community. For example, electrical line workers or engineers often have advanced skills that enrich a community. Each year the Northwest Public Power Association gives out awards for various forms of community service. Annually there are awards for line crew members or engineers with training in advanced first aid that have saved lives of community members while either on the job or while they were not at work.

A similar benefit happens when the people that plan, design and operate the utility have their families served by the same utility they work for. This makes electric reliability and ease of storm outage restoration a more personal and important aspect of their job. It also results in informal patrolling of distribution lines as employees drive to and from work for poles that have deteriorated, transformers that may be discolored due to overloading, or danger trees that may fall over in the next storm. When most electric utility employees live outside the service area, these benefits are reduced.

Another aspect of local control is local accountability. For example, many utility manages and City Council members have had neighbors or friends ask about the causes of extended outages or high electrical rates. This creates "peer pressure" on these leaders to focus their attention on meeting local needs. It also provides for a local education and public relations. For example, a person at a little league game or standing in line at the grocery checkout counter with someone who works at the local electric utility who is known to the person, concerns and issues can be discussed and the reasons why certain things are done the way they are. Can be learned

A different perspective on this type of peer pressure is that city council or utility board meetings are regularly scheduled and most have public comment periods. This allows meetings at which customers can attend without spending a lot of travel time to personally express concerns about utility policy or programs, gain an understanding of the issues and ask for change. The ability of the decision makers and the regulators of a privately held electric utility are much more remote and less accessible.

Another non-economic aspect of a City electric utility is community support. Many small electric utilities provide parks, trails and other benefits to their community. Seattle City Light has provided a number of small parks associated with abandoned substations and regularly includes public spaces and picnic areas adjacent to new substations. Chelan County PUD, Lewis County PUD, and the City of Blaine all have park facilities that were provided by the electric utility. Many consumer owned electric utilities install holiday and special event temporary lighting, and public signs or banners with electrical crews.

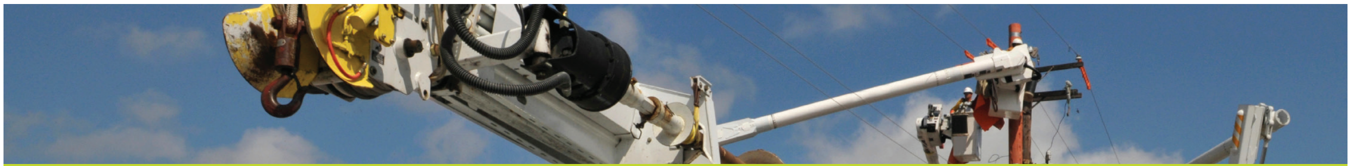
The American Public Power Association (APPA) has a list of benefits that are also associated with public power electric utilities. The APPA list is provided as Appendix C. APPA also has a very good primer on forming a new municipal electric utility and the reasons and challenges that are likely to be faced[20].

[20]http://www.publicpower.org/files/PDFs/Summary_of_Public_Power_for_Your_Community.pdf

New Public Power Utilities

Many cities and municipal entities nationwide have established new public power utilities in the past. Appendix B attached to this report is a list provided by the American Public Power Association of new consumer-owned electric utilities that have been formed since 1973. The list includes 88 publicly-owned electric utilities that began operations between 1973 and 2015. Many of these new public power utilities were formed from the service areas of investor-owned utilities.

In addition to the new public power utilities that have formed and are operating many other communities have evaluated the potential costs and benefits of providing electric service in their communities. The primary purpose in pursuing a public power utility has been to establish reliable, cost effective electric service and allow for local community-focused input as to how electric service is provided in their communities.



Fact Sheet

June 2014

BPA and new public utilities

While public utilities are common in the Northwest, the formation of a new publicly owned utility is rare. In fact, by 1949, there were more than 120 such utilities being served by the Bonneville Power Administration and there have been only eight more since. However, increases in electric utility costs have recently prompted grass-roots organizations to begin investigating the possibility of creating new publicly owned utilities.

In theory, these new utilities would acquire inexpensive power from BPA, a nonprofit federal power marketing administration that sells wholesale electricity, and be able to provide their customers with power that is less expensive than is currently available.

As a result, interest in BPA's policy on the creation of new utilities has increased. It is important to understand that BPA is absolutely neutral on whether new public utilities form or where they form.

In 2008, BPA completed a multiyear process to define how and under what conditions BPA will supply power to regional utilities under new long-term contracts that went into effect Oct. 1, 2011. Considering how long it takes to form a new utility, interested parties are well advised to consider BPA's Long-Term Regional Dialogue Policy and what it says about new utilities.

PUBLIC UTILITY DISTRICT NO.1
JEFFERSON COUNTY

BPA's newest publicly owned utility customer, Jefferson County PUD, began receiving BPA power April 1, 2013.

BPA's Regional Dialogue Policy for serving newly formed public utilities is designed to strike a balance between providing new publics significant access to BPA's lowest-cost power and setting a limit on the costs that would dilute benefits to existing purchasers at BPA's lowest-cost rates.

Since the new policy was adopted, one new publicly-owned utility has formed. Jefferson County PUD, located in the northwest corner of Washington state, began receiving power April 1, 2013. The PUD purchases 46 average megawatts to serve about 18,000 customers.

What constitutes a "new public" utility?

To be eligible to purchase power from BPA on a preference and priority basis, an applicant must meet three fundamental requirements. First, the prospective applicant must meet the statutory definition of the terms "public body" or "cooperative." The Bonneville

Project Act defines "public body" or "public bodies" to mean "States, public power districts, counties, and municipalities, including agencies or subdivisions of any thereof." It also defines "cooperative" or "cooperatives" to mean "any form of nonprofit-making organization or organization of citizens supplying, or which may be created to supply, members with any kind of goods, commodities, or services, as nearly as possible at cost."

The second requirement is that a public body or cooperative applicant be in the public business of selling and distributing the federal power to be purchased from BPA. If not currently in business, the Act directs BPA to afford the prospective customer a reasonable time, as determined by the administrator, to allow it to get into the public business of selling and distributing power.

The third requirement is that the prospective new utility be within the BPA service territory — Oregon, Washington, Idaho and western Montana.

Can BPA deny a request for service from a public entity that meets the legal definitions above?

The Northwest Power Act requires that BPA offer a contract for service to a public body or cooperative utility whenever requested for its net requirements load, even if it means BPA must acquire power to serve a new request.

BPA may only deny such a request if the applicant has failed after a "reasonable time" has passed to obtain necessary financing to get itself into the business of selling and distributing electric energy.

Determining a reasonable time period is at the BPA administrator's discretion.

Why are applicants allowed a "reasonable" period to set up their business?

The parties are to be given reasonable opportunity and time to hold any elections or to take any other necessary action to create a public body or cooperative. Once created, the public body or cooperative is to be afforded reasonable time and opportunity to authorize and issue bonds, or to arrange other financing necessary to construct or acquire necessary and desirable electric distribution facilities and to become in all other respects a qualified purchaser and distributor of federal power.

How does a customer become eligible to purchase federal power from BPA?

In addition to the standards outlined above, the applicant must meet BPA's "Standards for Service" as revised in January 2000.

What are BPA's standards for service?

BPA requires that the applicant:

- be legally formed in accordance with local, state, tribal or federal laws;
- own a distribution system and be ready, willing and able to take power from BPA within a reasonable period of time;
- have a general utility responsibility within the service area;
- have the financial ability to pay BPA for the federal power it purchases;
- have adequate utility operations and structure; and
- be able to purchase power in wholesale amounts.

In addition, the standards for service address matters related to the configuration and operation of electrical facilities, including the need to have an electrical plan of service and the ability to operate electrical facilities in a safe and reliable manner.

How does a new public apply for service under a Regional Dialogue contract?

A new public utility that qualifies for BPA service must request service from BPA through a three-year binding notice before it may buy federal power at BPA's Tier 1 rate (expected to be its lowest rate). The notice may be made at any point after the new public meets the standards for service. The contract high water mark — the contract right used to determine eligibility to buy

Tier 1 power — for a new public will be set at the customer's net requirement level in the year deliveries begin. There is the potential for a slight reduction or increase so that the new public's load has similar access to lowest-cost rates as that of existing publics.

What led to BPA's approach to new publics in the Regional Dialogue?

BPA has earmarked 250 average megawatts of high water marks for service to the net requirement loads of new public customers in order to make federal power at the Tier 1 rate more widely available while providing planning certainty for the amount of power that BPA may need to acquire to serve load in the future.

One of BPA's rate-setting requirements is to encourage the widest possible diversified use of electric power. BPA believes that excluding new publics from an opportunity to obtain power at the Tier 1 rate would place them in an unfavorable position and would not promote the widest possible use of federal power. However, BPA also wishes to ensure that utilities receive price signals that more directly represent the true incremental costs of load growth. The 250 aMW is intended to strike a reasonable balance in achieving these objectives.

What is a contract high water mark?

BPA is limiting its sale of wholesale power at a Tier 1 rate to the output of the federal system, plus a limited amount of augmentation. Each utility's "contract high water mark," or CHWM, sets the contract right used to determine eligibility for Tier 1 power.

Tier 1 power will be sold consistent with the amount of power available from the federal system with limited augmentation. What "augmentation" is included in Tier 1 rates?

Some features in the Regional Dialogue Policy leave Tier 1 rates and costs somewhat higher than they otherwise would be. These include the proposals for resource removal, up to 250 aMW of power for new publics and up to 300 aMW of augmentation for existing publics. BPA believes that these limited cost and rate impacts are reasonable in light of the other key interests they would serve.

BPA will most likely have to augment to meet any new public's request, but it isn't a given. There is a chance, albeit small, that there would be enough power in the existing Federal Base System to serve some of the 250 aMW of new public requests.

What happens if total eligible high water mark requests exceed the limit for the rate period?

When the total eligible high water mark requests exceed the 50 aMW limit in a two year rate period, individual HWM amounts of new publics will be prorated down to meet the limit. Amounts not provided to any new public due to the 50 aMW limit will automatically be added to eligible amounts in the next rate period.

How will BPA prevent larger new publics from using up the available Tier 1 allotment?

During the first year of eligibility for a high water mark, all utilities would be eligible for the lesser of their load or 10 average megawatts. To ensure that access to the 250 aMW is spread broadly and not used solely by one large new public utility, utilities larger than 10 aMW would have their HWM amounts over 10 aMW phased in two-year increments if there is more than one new public formed and their requests exceed the 50 aMW yearly cap. The phasing-in would be 33.3 percent for the next 24 aMW of HWM and 20 percent for any remaining HWM amount after that. It is worth noting that Jefferson County PUD has a 46-megawatt high water mark, leaving a little over 200 aMW for service to the net requirement loads of new public customers at Tier 1 rates.

What are the exceptions to the 50 aMW rate-period limit?

Small Utility Exception. Because this type of pro rata reduction could inordinately impact a small customer, BPA proposes that the first five new publics smaller than 10 aMW that would otherwise be affected by the

50 aMW limit will receive their full HWM without reduction. Since this will only happen when rate-period limits are exceeded and is limited to five customers, BPA believes this accommodation for small publics still meets the region's interests while taking care of the special needs of these customers.

Tribal Utility Exception. BPA has earmarked 40 aMW for additions of contract high water marks for the load growth and annexed loads of tribal utilities. These additions will potentially add to the 50 aMW limit for the rate period.

What happens if a new public is formed from an existing public?

New public customers that form out of an existing public utility will receive a percentage of the existing public utility's CHWM equal to their proportion of the existing utility's total retail load. If the utilities involved agree on the CHWM split, we will use their numbers. If not, BPA will take into account information received from the involved utilities about the characteristics of the load when we determine the high water mark.

What happens if a new public is formed from an investor-owned utility?

New publics that form out of an existing IOU will be eligible for CHWMs within the new publics limits discussed above.

Are tribes eligible to form new public utilities?

A federally recognized tribe that forms a cooperative utility pursuant to its tribal constitution and laws would be eligible for preference status. However, a tribe could not create a cooperative inconsistent with state law for service to nontribal members or outside the tribe's jurisdiction.

What happens if a new large single load is embedded in a request for service by a newly formed public utility?

BPA's New Large Single Load (NLSL) Policy applies to consumer load within a new public's proposed service territory or expansion. Such load will be treated like any new large single load if it is 10 aMW or more at the time the new public is formed, regardless of when the load started taking service from the existing supplier.

How are new publics treated with regard to the Residential Exchange Program?

A new public customer that chooses to sign a contract with a CHWM would have the same access to the Residential Exchange Program as an existing public customer that signs a CHWM contract.

What does BPA expect in terms of new publics forming?

BPA believes new public customers, in addition to Jefferson County PUD, are likely to form and request service during the term of the Regional Dialogue contracts, which extend into 2028. However, such formations are not likely to involve large amounts of load. Over the past 25 years, a little over 300 average megawatts of new publics have formed and taken PF service. For the 20-year term of the Regional Dialogue contracts, BPA will earmark 250 aMW that, adjusted for the five-year time difference and the potential for additional amounts for small utilities, provides an amount of power for new publics that is approximately equivalent to this recent history.

Appendix B
Publicly Owned Electric Utilities
Established 1973-2011

85 new public power utilities began operating, 41 of the new systems were formed in service areas of investor-owned utilities; the others were formerly served by non-utility businesses, federal agencies or local publicly owned utilities. This list does not include communities that were previously served by investor-owned utilities or rural electric cooperatives and instead joined existing public power systems.

New Utility Formed	State	Year Est.	Previous Supplier
City of Atka (42 customers)	ALASKA	2008	Andreanof Electric Corporation*
Island Power, Pittsburg, Calif. (400 customers)	CALIFORNIA	2006	Former military base
Winter Park (13,750 customers)	FLORIDA	2005	Progress Energy*
Berea (4,700 customers)	KENTUCKY	2005	Berea College Electric Utility
Moreno Valley Utilities (4,300 customers)	CALIFORNIA	2004	SCE*
Huron (2 customers)	OHIO	2004	Ohio Edison*
Elk City (8 customers)	OKLAHOMA	2004	AEP*
Electric City Power, Great Falls, Montana (large governmental and industrial customers)	MONTANA	2004	NorthWestern Energy
City of Williams (1,721 customers)	ARIZONA	2003	Arizona Public Service*
McAllister Ranch Irrigation District[1]	CALIFORNIA	2003	PG&E*
Rancho Cucamonga Municipal Utility[1] (400 customers/commercial and industrial)	CALIFORNIA	2004	SCE*
Industry, California[1] (23 customers)	CALIFORNIA	2003	SCE*
Port of Stockton Electric[1] (3,208 customers)	CALIFORNIA	2003	PG&E*
City of Victorville[1]	CALIFORNIA	2003	SCE*
Hercules Municipal Utility[1] (825 customers)	CALIFORNIA	2002	PG&E*
Corona Municipal Electric Utility[1] (1,700 customers)	CALIFORNIA	2001	SCE*

[1] A "greenfield growth area" project, serving new industrial and/or residential development.

New Utility Formed	State	Year Est.	Previous Supplier
Hermiston (5,123 customers)	OREGON	2001	PacifiCorp*
Long Island Power Authority (1,090,538 customers)	NEW YORK	1998	Long Island Lighting Company*
Town of Eagle Mountain (382 customers)	UTAH	1998	New Community
Ak-Chin Electric Utility Authority (378 customers)	ARIZONA	1997	Arizona Public Service*
Hohokam Irrigation & Drainage District (498 customers)	ARIZONA	1997	Arizona Public Service*
Village of Obetz (14 customers)	OHIO	1997	American Electric Power Co.*
Merced Irrigation District[2] (3,157 customers)	CALIFORNIA	1996	Pacific Gas & Electric*
Mohegan Tribal Utility Authority (54 customers)	CONNECTICUT	1996	New Entity
MassDevelopment Devens Utility (100 commercial customers)	MASSACHUSETTS	1996	Former Military Base
Tarentum Borough (2,651 customers)	PENNSYLVANIA	1996	West Penn Power*
Bozrah Light & Power (2,587 customers)	CONNECTICUT	1995	Bozrah Light & Power (private company)*
City of Broken Bow (5 customers)	OKLAHOMA	1995	Public Service Company of Oklahoma*
Asotin County Public Utility District No. 1 (3 customers)	WASHINGTON	1994	Clearwater Power Company*
Byng (53 customers)	OKLAHOMA	1990	Oklahoma Gas & Electric*
Clyde Light & Power (2,872 customers)	OHIO	1989	Toledo Edison*
City of Santa Clara (1,707 customers)	UTAH	1989	Utah Power & Light*
Hayfork Valley Public Utility District (724 customers) (Merged with Trinity County PUD in 1993)	CALIFORNIA	1988	Pacific Gas & Electric*
Lassen Municipal Utility District (12,059 customers)	CALIFORNIA	1988	CP National*
City of Scribner (589) customers	NEBRASKA	1988	Nebraska Public Power District

[2] Merced Irrigation District, Calif., began distribution utility in 1996.

New Utility Formed	State	Year Est.	Previous Supplier
City of Riverdale (206 customers)	NORTH DAKOTA	1988	Corps of Engineers
City of San Saba Electric Utility (2,196 customers)	TEXAS	1988	Lower Colorado River Authority
City of Washington (5,750 customers)	UTAH	1988	Utah Power & Light*
Electrical District #8 of Maricopa County (456 customers)	ARIZONA	1987	Arizona Public Service*
Town of Fredonia (731customers)	ARIZONA	1987	CP National*
Reedy Creek Improvement District (1,213 customers)	FLORIDA	1987	New Entity
Troy Power & Light (923 customers)	MONTANA	1987	Montana Light & Power*
Kerrville Public Utility Board (20,157 customers)	TEXAS	1987	Lower Colorado River Authority
Kanab City Corporation (1,378 customers) (Sold to Garkane Energy Cooperative in 2004)	UTAH	1987	Utah Power & Light*
Town of Pickstown (63 customers)	SOUTH DAKOTA	1986	Corps of Engineers
City of San Marcos Electric Utility District (20,320 customers)	TEXAS	1986	Lower Colorado River Authority
Strawberry Electric Service District (2,972 customers)	UTAH	1986	Strawberry Waters Users
City of Galena (335 customers)	ALASKA	1985	M & D Enterprises
Page Electric Utility (3,780 customers)	ARIZONA	1985	Arizona Public Service*
Ipnatchiaq Electric Co. (67 customers)	ALASKA	1984	Supplier Unknown
Larsen Bay Utility Co. (86 customers)	ALASKA	1984	Individual Generators
Aguila Irrigation District (39 customers)	ARIZONA	1984	Supplier Unknown
Columbia River People's Utility District (St. Helens, Oregon) (17,347 customers)	OREGON	1984	Pacific Power & Light*
Kwig Power Co. (111 customers)	ALASKA	1983	Supplier Unknown

New Utility Formed	State	Year Est.	Previous Supplier
St. Paul Municipal Electric Utility (231 customers)	ALASKA	1983	Federal Government
City of Thorne Bay Utilities (261 customers) (Sold to Alaska Power & Telephone* in 2001)	ALASKA	1983	Federal Government
Needles Department of Public Utilities (2,092 customers)	CALIFORNIA	1983	CP National*
Tuolumne County Public Power Agency (30 customers)	CALIFORNIA	1983	Pacific Gas & Electric*
Emerald People's Utility District (Eugene, Oregon) (18,104 customers)	OREGON	1983	Pacific Power & Light*
Akutan Electric Utility (65 customers)	ALASKA	1982	Supplier Unknown
City of Kotlik Utility (176 customers)	ALASKA	1982	Supplier Unknown
City of White Mountain (101 customers)	ALASKA	1982	Supplier Unknown
Trinity County Public Utility District (6,797 customers)	CALIFORNIA	1982	CP National*
City of Chignik (87 customers)	ALASKA	1981	Sea Alaska
Massena Electric Department (9,406 customers)	NEW YORK	1981	Niagara Mohawk*
Markham Hydro Distribution, Inc. (62,126 customers)	ONTARIO	1979	Supplier Unknown
Tatitlek Electric Authority (55 customers)	ALASKA	1978	Supplier Unknown
White, City of (254 customers)	SOUTH DAKOTA	1978	Supplier Unknown
Tlingit Haida Regional Electric Authority (1,268 customers)	ALASKA	1977	Supplier Unknown
Tonopah Irrigation District (31 customers)	ARIZONA	1977	Supplier Unknown
Sherrill, City of (1,884 customers)	NEW YORK	1977	Supplier Unknown
Manokotak, City of (136 customers)	ALASKA	1976	Supplier Unknown
Ellaville, City of (958 customers)	GEORGIA	1976	Supplier Unknown
Anthon, City of (374 customers)	IOWA	1976	Supplier Unknown
Kiowa, City of (753 customers)	KANSAS	1976	Supplier Unknown

Matinicus Plantation Electric Co. (120 customers)	MAINE	1976	Supplier Unknown
North Slope Borough Dept. of Municipal Services (1,180 customers)	ALASKA	1975	Supplier Unknown
De Witt, Village of (313 customers)	NEBRASKA	1975	Supplier Unknown
Hurricane Power Committee (5,229 customers)	UTAH	1975	Supplier Unknown
Tohono O'odam Utility Authority (3,746 customers)	ARIZONA	1974	Supplier Unknown
Lyons, Town of (1,095 customers)	COLORADO	1974	Supplier Unknown
Aurelia, City of (555 customers)	IOWA	1974	Supplier Unknown
Stanton, City of (228 customers)	NORTH DAKOTA	1974	Supplier Unknown
Kirbyville Light & Power Co. (1,318 customers)	TEXAS	1974	Supplier Unknown
Hobgood, Town of (324 customers)	NORTH CAROLINA	1973	Supplier Unknown

* Represents an investor-owned utility

Source: ***American Public Power Association (2012)***

"Customers" refers to the number of customer-meters served. The population served would be some multiple of this number.

Publicly Owned Electric Utilities Established 2005-2015

During this period 8 new public power utilities began operating (6 were formed from the service areas of investor-owned utilities). This list does not include communities that were previously served by investor-owned utilities or rural electric cooperatives and instead joined existing public power systems.

New Utility Formed	State	Year Est.	Previous Supplier
Jefferson County, Wash. (18,000 customers)	WASHINGTON	2013	Puget Sound Energy*
Toledo Public Power (1 customer)	OHIO	2012	First Energy*
City of Egegik (77 customers)	ALASKA	2011	Egegik Light & Power Company*
City of Atka (42 customers)	ALASKA	2008	Andreanof Electric Corporation*
Island, Power, Pittsburg, Calif. (400 customers)	CALIFORNIA	2006	Former Military Base
Winter Park (13,750 customers)	FLORIDA	2005	Progress Energy*
Berea (4,700 customers)	KENTUCKY	2005	Berea College Electric Utility
Cerritos (60 customers)	CALIFORNIA	2005	SCE*

"Customers" refers to the number of customer-meters served. The population served would be some multiple of this number.
Source: American Public Power Association (2016)

*Represents an investor-owned utility

American Public Power Association

Public Power: Shining a Light on Public Service

Public Power is Hometown Power

More than 2,000 cities and towns in the United States light up their homes, businesses and streets with "public power"—electricity that comes from a community-owned and -operated utility. Each public power utility is different, reflecting its hometown characteristics and values, but all have a common purpose: providing reliable and safe not-for-profit electricity at a reasonable price while protecting the environment. While the vast majority are owned by cities and towns, a number of counties, public utility districts, and even a handful of states have public power utilities. Most—especially the smaller ones—are governed by a city council, while others are overseen by an independently elected or appointed board.

47 million

Number of people served by public power

Lower Costs Boost Local Economies

Unlike private power companies, public power utilities are public service institutions and do not serve stockholders. Instead, their mission is to serve their customers. They measure success by how much money stays within the community through low rates and contributions to the city budget, not how much goes out to stockholders across the country and around the world.

On a national basis, private power residential customers pay average electricity rates that are about 14 percent more than those paid by public power customers. On average, public power utilities return to state and local governments in-lieu-of-tax payments and other contributions that are 33 percent greater than state and local taxes paid by private power companies. Public power utilities lower costs through their partnerships with other local government departments and other organizations. There are more than 70 joint action agencies that operate within states or regions to offer local utilities power supply or other services.

APPA's national subsidiary, Hometown Connections, provides a portfolio of lower-cost products and services.

Public Power is Customer-Focused

For more than 130 years, public power has been a tradition that works across the nation on behalf of its communities and customers. Today, it is a thriving segment of the electric utility industry, enhancing overall economic development, often with additional infrastructure responsibilities for broadband services. Public power has a strong environmental-protection track record, solid credentials with bond ratings agencies, and a reputation for reliable, customer-focused service. Public power also continues to be an appealing institution for many cities and towns currently served by private power companies and interested in the opportunity to obtain lower rates and local control over an essential service. Growing failures of wholesale electricity markets—especially those run by regional transmission organizations—and the impacts of these failures on wholesale and retail customers are priority issues for public power. Climate change, environmental protection, and energy efficiency; maintaining and enhancing reliability; developing new generation and other power supply options; and financing infrastructure are all high on public power's agenda.

Electric Industry Ownership and Consumers

Number and type of provider	% of customers served
2,006 public power systems	15%
193 investor-owned electric utilities	68%
873 rural electric cooperatives	13%
181 power marketers	4%

Public Power Has a Voice in Washington

Public power utilities work collectively through the American Public Power Association to ensure policies that put customers first and ensure a stable supply of electricity while protecting the environment. Since two-thirds of public power utilities do not generate their own electricity, and instead buy it on the wholesale market for distribution to their customers, securing competitively priced and reliable wholesale power is a priority.

3 million

Number of business customers served by public power nationwide

The American Public Power Association is the service organization for the nation's more than 2,000 community- and state-owned electric utilities. It represents public power's interests in Washington, D.C., and provides an array of services to help its members with managerial and operational issues.

More Facts About Public Power:

49 — Number of states with public power systems (all but Hawaii)

2,006 — Number of public power systems in the U.S.

1880 — Year first public power systems were created

2021 — Year by which half of all public power systems will celebrate a centennial

1,400 — Number of public power systems serving communities with populations of 10,000 or fewer

1.4 million — Number of customers served by the largest municipally owned public power utility, the Los Angeles Department of Water & Power